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AND DEVELOPMENT COMMISSION
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ON
GEOTHERMAL-RENEWABLE ISSUES

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1 P R O C E E D I N G S

2 COMMISSIONER GEESMAN: This is a
3 workshop of the Commission's Integrated Energy
4 Policy Report Committee. I'm John Geesman, the
5 Presiding Member of the Committee. To my left is
6 Commissioner Jim Boyd, the Associate Member of the
7 Committee. To my right is Melissa Jones, my Staff
8 Advisor.

9 Topic today is to get a better handle on
10 transmission needs associated with geothermal
11 development. As you all know, the state has set
12 very aggressive goals for renewable sources of
13 electricity. We expect geothermal to be a primary
14 source of much of that capacity.

15 Each of the utilities have indicated a
16 sense of the suitability of the geothermal
17 resource for their needs, but we do find some
18 significant transmission constraints.

19 We've brought a great deal of attention
20 over the last couple for years to the transmission
21 constraints confronting the development of our
22 wind resource in California. With today's
23 workshop and follow-on activities, we hope to do a
24 similar service as it relates to development of
25 our geothermal resources. Commissioner Boyd?

1 COMMISSIONER BOYD: No, thank you. I
2 think you covered it all quite well. I look
3 forward to hearing what is presented today to try
4 to push this subject area forward. Thank you.

5 COMMISSIONER GEESMAN: Don, you want to
6 start?

7 MR. KONDOLEON: Okay. That being said,
8 I want to again welcome you to the Energy
9 Commission, and thank you so much for
10 participating in this workshop. This is a
11 collaborative effort, much the staff of the
12 transmission unit here at the Energy Commission,
13 and also the Geothermal Program within the PIER
14 Renewables Group.

15 That being said, why don't we start?
16 Jim Lovekin is going to give the first
17 presentation this morning.

18 MR. LOVEKIN: Good morning,
19 Commissioners and distinguished guests. My name
20 is Jim Lovekin and I'm with Geothermex. I'm
21 presenting this morning work that is essentially
22 the same as information that I presented a little
23 over a year ago.

24 It's a summary of work that Geothermex
25 has done as a contractor to the California Energy

1 Commission PIER Program, trying to identify
2 geothermal resources available in the near term
3 for development and to quantify the costs of those
4 from the point of view of the capital costs that
5 would be entailed to get them online.

6 So, those of you who have seen prior
7 workshops will have seen some of this. I've done
8 a little with it, improved the graphics, but I
9 think consistency is probably more important at
10 this stage, so you'll see a lot of this stuff that
11 you've seen before.

12 Okay, as I said, this is PIER-funded
13 study. The title of the study is "New Geothermal
14 Site Identification and Qualification." It's part
15 of the Hetch Hetchy/SFPUC Programmatic Renewable
16 Energy Project.

17 The principal authors were my co-workers
18 Chris Klein and Subir Sanyal, as well as myself.
19 The project coordination has been through the
20 Center For Resource Solutions, and our contact
21 there is Ray Cracker. And the Project Manager is
22 Valentino Tiangco at the CEC.

23 Just a brief overview of how this work
24 came to be. We entered into a contract with the
25 San Francisco Public Utilities Commission in

1 October of 2002. And this information, the data
2 is probably current as of about year end 2003. It
3 was submitted in a report to the CEC in April
4 2004.

5 There is a companion study currently
6 underway of existing facilities within California,
7 with an effort to identify opportunities for
8 improved technology both within the power block
9 and within the well fields. And also trying to
10 get a better handle on operating costs, which are
11 hard to quantify and seem to vary quite a bit from
12 project to project, but that study is scheduled
13 for completion in the middle of this year.

14 As I mentioned, the two main components
15 of the work we've published are to estimate the
16 geothermal reserves and to give realistic
17 estimates of capital costs. A challenge of the
18 project from the get-go is how do you compare
19 projects at various levels of maturity, everything
20 from existing power plants on line to things that
21 are little more than a gleam in a developers eye
22 supported by a hot spring or two.

23 And yet, at both ends of the spectrum
24 you have to take credit for the fact that there
25 could be real power out there, so we came up with

1 a ranking, just to sort of clear the air or to
2 divide the projects as to their level of maturity
3 for development.

4 We came up with these exploration
5 development categories:

6 "A" category would be where an existing
7 power plant is operating;

8 "B" would be where there is no operating
9 plant, but there is at least one well with a
10 tested capacity equivalent to one megawatt or
11 more;

12 "C" projects would be those in which no
13 wells have been tested at one megawatt or more,
14 but have a downhole temperature measured of at
15 least 212, or the boiling temperature of water at
16 atmospheric;

17 and "D", not meeting any of the above,
18 but there are resource properties from other
19 sources, either the general geology or the
20 geochemistry or the geophysics from which you have
21 reason to hope that a viable project could be
22 present.

23 This slide then sort of cuts to the
24 chase. It's a graphical summary of our
25 conclusions, and I'll show you a table with

1 similar information a little later.

2 The key here, if you look at the lower -
3 - let's see what we've got here. Okay, if I can
4 direct your attention to the very lower left
5 corner, there's a rather -- this map is keyed on
6 showing the resources available in Nevada and
7 California.

8 It has a rather complicated fraction
9 because there's lots of perspectives on the
10 resources that are available. So for both a
11 combined total, and for Nevada and California
12 separately, and for some subset areas, if you look
13 in the denominator you've got, well, we rated the
14 projects by both the minimum likely capacity to
15 come on line, and the most likely.

16 This was a statistical exercise that we
17 did based on heat in place, and I'll go into that
18 in a little more detail in a moment.

19 In the denominator then you've got the
20 minimum on the left and the most likely on the
21 right, and then in the numerator you've got the
22 incremental power available. In other words,
23 subtracting out the power that's already actively
24 on line. So you've got a minimum incremental and
25 a most likely incremental.

1 So there's a lot of information on here.
2 The lower left hand corner line is that,
3 incrementally, it looked like, for the combined
4 states of California and western Nevada you had
5 2,800 megawatts as a minimum, and incrementally
6 4,300 megawatts most likely.

7 Within California alone the numbers were
8 2,000 megawatts minimum incremental, and 3,000
9 megawatts most likely. And in Nevada you're
10 looking at numbers like 800 megawatts minimum
11 incremental and 1,300 megawatts most likely
12 incremental.

13 Within California it's clear that the
14 lion's share of this, both total capacity and
15 incremental is certainly, certainly the
16 incremental is in the Imperial Valley, a large
17 component of that being the Salton Sea, of
18 approximately 1,350 megawatts incremental minimum
19 and 1,950 most likely.

20 So there's a major concentration of
21 power here, or at least power potential. In
22 northern California we feel there is incremental
23 capacity still available in the geysers on the
24 order of 350 minimum, 550 most likely. And in
25 northern California, it was public information

1 about Medicine Lake, something on the order of 150
2 megawatts minimum, 200 megawatts most likely.

3 The Medicine Lake prospect, I would
4 comment that these numbers represent the sum of
5 two subsets of Medicine Lake, the so-called
6 Telephone Flat and Four Mile Hills areas. There
7 are other areas within Medicine Lake, and in fact
8 as part of our analysis we did sort of a Caldera-
9 wide analysis, which put that most likely number
10 more in the range of 300 megawatts.

11 That's part of the study, but for the
12 tabulations we basically added Four Mile Hill and
13 Telephone Flat separately. I should comment also
14 that within the state of California there are
15 other volcanic centers. The Mount Shasta area
16 comes to mind. We relied on, as I emphasized,
17 information that was in the public domain. Some
18 of the documentation on some of those other
19 volcanic centers were included in earlier
20 documents such as circular 790 of the USGS back in
21 1979, but that document did not per se quantify
22 the megawatts available at those locations.

23 Suffice to say, they're out there, not
24 as well quantified, but substantial.

25 Looking at Nevada, and this study did

1 include Nevada because of the possibility of
2 bringing Nevada geothermal resources into the
3 California market either through this so-called
4 HVDC or high voltage direct current line.

5 Other members of the PIER review team
6 were looking at the possibility of a tap into the
7 HVDC lines somewhere in the Reno area, so we put
8 this odd-shaped but topography based pink polygon
9 there, and called it greater Reno.

10 We also called an area, again mainly
11 based on topography in an existing privately owned
12 transmission line, we called it the Dixie
13 Corridor. So, in Nevada we basically lumped them
14 into greater Reno, the Dixie Corridor, and other.

15 So greater Reno was on the order of 400
16 megawatts minimum incremental, 650 most likely.
17 The Dixie Corridor, tying in there somewhere
18 around Bishop, has a potential of 300 megawatts
19 incremental, 500 most likely.

20 So it's a lot to swallow, it's all in
21 that map, but it sort of shows you the areas we
22 were looking at specifically, this question of how
23 out of state resources could get tied in, and then
24 stating, you know, what should be obvious, which
25 is that there's a large concentration of

1 geothermal potential here in the south and
2 significant concentrations still in northern
3 California.

4 I've mentioned that this was a
5 statistical approach. It's based on heat in
6 place. Basically, to calculate the volumetric
7 heat in place you look at the reservoir area, the
8 thickness, the ferocity, temperature, and a
9 recovery factor.

10 I would say that the main difference
11 between our work and the work of the USGS,
12 although the methodology's are similar, is that
13 over the years we have seen a recovery factor of,
14 a more conservative recovery factor seems to be
15 appropriate. So we have a recovery factor in the
16 range of 5 to 20 percent, whereas I think the USGS
17 used something on the order of 25 percent as the
18 average value.

19 There are some other fixed parameters
20 that have to do with the rock properties, the
21 volumetric heat capacity, your re-injection
22 temperature, some factors pertaining to the plant
23 life -- we used a 30 year plant life and
24 utilization factor of .45, capacity factor of 90
25 percent.

1 And so, in this particular example here
2 in Fishlake Valley, you come up with a
3 distribution that you can express either as a
4 histogram or as a cumulative probability function,
5 and the minimum case is basically the 90 percent
6 case on the cumulative probability function.

7 So for this case it comes in here at
8 about 30 megawatts, and the most likely case is
9 defined as the mode of this histogram indicated
10 distribution, and it's approximately the 50
11 percent case, although the statistics can vary
12 either side of that. But it should be the tallest
13 histogram in this Monte Carlo exercise.

14 That's how we came up with our minimum
15 and most likely cases. I emphasize they're based
16 on heat and place. They don't necessarily say
17 anything about permeability or produceability, but
18 we tried to find for those later considerations
19 when we were looking at costs and the exploration
20 and capital development costs that would be
21 required.

22 In tabular form, for those that work
23 better that way, this is basically the same
24 information that was on the map. California on
25 the top of the graph, then Nevada. It may be hard

1 to see from where you're sitting, but there's the
2 2,000 and 3,000 megawatts of incremental capacity
3 for minimum -- and I should emphasize these are
4 gross megawatt numbers -- and for Nevada we're
5 looking at 800 and 1,300 for minimum and most
6 likely.

7 The right hand most columns make the
8 point that, within California, the Imperial Valley
9 is like 65 percent of the total and it's like 45
10 percent of the total for both states combined.

11 Within Nevada, greater Reno accounts for
12 about 50 percent of the capacity of what's in
13 western Nevada.

14 So looking at the costs, we looked at
15 several components of this. Exploration, which we
16 defined as up to but not including the cost of the
17 first full-diameter well. IN other words it's the
18 work that you undertake to site that well and
19 design it and get ready to drill, but it doesn't
20 actually include any full-size well drilling.

21 Confirmation was the drilling costs and
22 the additional geophysics or whatever you needed
23 to demonstrate 25 percent of the specified
24 capacity, your target capacity for your project,
25 as available at the well head. We've found over

1 the years that financial institutions looking to
2 finance projects tend to insist on at least that
3 amount before they'll make that available to
4 projects going forward. so everything up to that
5 point is pretty much equity, venture capital.

6 Development costs, primarily drilling up
7 to the point of somewhat more than 100 percent of
8 the specific capacity to allow for declines. We
9 used 105 percent available at the wellhead. Your
10 plant, your turbine and generator equipment and
11 all the other surface facility which we handled
12 for the purposes of this study in a rather broad
13 brush of \$1,500 per kilowatt across the board.

14 We also looked at transmission line
15 interconnection, which is not included in the
16 \$1,500 per kilowatt, but was part of the overall
17 costs of development that we included for this
18 study.

19 And for that we relied on our fellow
20 PIER contractor, Electranix, who looked at several
21 different scenarios for different regions, they
22 had sort of a region-wide upgrade for greater
23 Reno, and what we did there was we took the total
24 upgrade costs and then apportioned it among
25 geothermal projects in the are based on megawatts.

1 So it's nothing quite as simplistic as dollars per
2 mile, it is fairly grounded, but it is still a
3 very rough cut.

4 There was also an effort made to look at
5 the Imperial Valley and its transmission
6 constraints. So it's a sort of a complicated
7 interaction between the other contractor,
8 Electranix, and ourselves, but we did try and
9 capture those transmission costs in our work.

10 COMMISSIONER GEESMAN: Would that at
11 least implicitly assume a simultaneous development
12 of all of the geothermal prospects within the
13 particular well field or --

14 MR. LOVEKIN: Within that particular
15 area. For instance, greater Reno, that is
16 correct. Because what we found is, it's the case
17 of shooting lead horse. Whoever gets out there to
18 try and put the transmission in place ends up
19 bearing, under the simplistic model, the lion's
20 share of the cost, which would kill any single
21 project. So that was our way around that.

22 COMMISSIONER GEESMAN: Thank you.

23 MR. LOVEKIN: We also looked at drilling
24 costs as part of our exercise, again relying on
25 information of what was in the public domain and

1 what certain operators chose to share with us. So
2 we've got information here from East Mesa, the
3 Geysers, Heber, Medicine Lake.

4 We distinguished between Salton Sea
5 producers and Salton Sea injectors, because the
6 producers are sort of a special breed of cat with
7 titanium casings in them, and you can see they
8 float above the general trends here, the open
9 triangles.

10 The injectors, however, within the error
11 of this, feel pretty much within trend. We also,
12 to flesh it out a little bit, included some
13 information from overseas, the Azores, El
14 Salvador, and Guatemala, and then we fit it with a
15 second order polynomial, although for the scatter
16 you could almost do it as well with a straight
17 line.

18 But we wanted to capture sort of the
19 intuition that as you get very deep it should be
20 concave up. And so we came up with this
21 correlation there, which I won't read out to you.
22 It's in your notes. It has a statistical
23 correlation indicator, R squared, of just a little
24 over half.

25 So, there are a lot of factors that

1 affect cost of geothermal drilling. We went into
2 the exercise knowing that, but you can account for
3 somewhat more than half of that statistical
4 variation if you just limit that.

5 I should say also that these costs were
6 escalated to year end 2003 dollars. They probably
7 don't fully capture the run-up in steel prices and
8 casing costs that occur in late 2003, early 2004,
9 and are with us here today. Not to mention rig
10 availability costs, which in general I would say
11 they're either on the low side, given the rig
12 availability at present, and casing costs.

13 So, with those caveats, we looked at
14 capital costs for 64 projects, and averaging
15 within both California and western Nevada -- I
16 should comment that that whole raft of projects
17 that we looked at included obviously some that
18 were obviously economic and some that were
19 obviously uneconomic, but the goal here was to
20 sort of show the spectrum, because so much of what
21 is actually going to get done is going to be a
22 function of public policy, and people need to know
23 sort of the basket of geothermal resources that
24 are out there.

25 So this average includes things that are

1 upwards of \$6,000 per kilowatt, that are in the
2 average, as well as some things that are under
3 \$2,000 per kilowatt. \$3,100 per kilowatt
4 installed reflects all of the development costs
5 including transmission.

6 The average in California was somewhat
7 less, \$2,950 per kilowatt in California. somewhat
8 higher in the greater Reno and Dixie Corridor
9 areas, \$3,400 per kilowatt.

10 The incremental geothermal capacity
11 available, 2,500 megawatts below the \$3,100 per
12 kilowatt average. In California, below the
13 California average it's like 2,000 megawatts
14 gross.

15 If you assign \$2,400 per kilowatt, which
16 we said is the assumed threshold to be competitive
17 with other renewables, you've got on the order of
18 1,700 megawatts gross, and virtually all of that
19 is within California. It's a negligible amount
20 that's outside, from the information we had
21 available.

22 As we've always been saying, this is
23 subject to further updating ,to the extent that
24 operators and developers give us comments on the
25 report, and then give us more specificity on their

1 particular operating costs, but obviously there's
2 a certain sensitivity, and people treat that kind
3 of information with some kind of proprietary
4 concerns.

5 I want to emphasize too, or just put in
6 a plug if you will, this was the PIER geothermal
7 database. It's just one of the screens within the
8 database, but this information -- we issued a
9 report, it looks like this, it stands about 3/4 of
10 an inch thick. You can download that, it's about
11 five megabytes.

12 The underpinning of it though is 50
13 megabyte access database, which is easily
14 accessible, if you'll pardon the pun. You don't
15 have to know Access programming language to use
16 the database, and I think it's some of the more
17 substantive contributions of the PIER-funded work,
18 and it's out there and available.

19 It goes through all the projects that we
20 listed, not only the 64 for which we made cost
21 estimates, but there was something north of 80
22 projects that we actually got megawatt estimates
23 for.

24 How to get a copy, as I mentioned,
25 they're available for free download. It happens

1 to be at our website. Just go to our home page
2 and click on CEC PIER Reports, and as I say the
3 report itself is 4.2 megawatts, the database is
4 like 45 megabytes.

5 In summary, we estimate incremental most
6 likely reserve between the two states, again
7 western Nevada included in this, only the western
8 portion of Nevada, 3,300 megawatts, and the
9 incremental within California is about 3,000
10 megawatts, most likely scenario. The cost average
11 overall, \$3,100 per kilowatt, including an
12 estimate of transmission tie-in.

13 And the power available in gross
14 megawatts below a \$2,400 per kilowatt threshold
15 was on the order of 1,700 megawatts, virtually all
16 of that in California.

17 I have a few other slides that will help
18 me answer any questions, if there are any
19 questions?

20 (inaudible question asked)

21 The answer there, the question is how
22 sustainable is geothermal beyond the 30-year
23 project life? And in practice what we see is that
24 there are fields that have operated much longer
25 than 30 years.

1 I think that, as these projects have
2 developed, you know, you would probably hone in on
3 the actual reserve numbers that are available,
4 site by site, so I think it would be a mis-
5 impression to expect that they're all going to
6 become uneconomic after 30 years. I think we've
7 got a much longer life in all these projects.

8 This is a fairly conservative approach.
9 In some measure it's an antidote to historical
10 estimates, which I think generally came to be
11 regarded as overly optimistic, but by the same
12 token, this only takes credit for the stuff that
13 we know right now, and the stuff that we know in
14 the public domain.

15 So I think the short answer is I would
16 expect virtually all of these projects to be
17 continuing, and so much of it is going to depend
18 on the price of energy, you know, it's going to be
19 very -- my crystal ball of what's going to be
20 going on under the ground is I think a lot clearer
21 than people's crystal ball of what energy prices
22 are going to be out 30 years.

23 If we can just get them up and running
24 and get the transmission lines built, I have a
25 good hunch that they're going to be around and

1 operating much longer. My crystal ball. Other
2 questions?

3 COMMISSIONER GEESMAN: What did your
4 cost numbers assume about a production tax credit
5 or other federal tax incentive?

6 MR. LOVEKIN: This study, again
7 completed on data through 2003, we didn't really
8 incorporate production tax credit specifically in
9 there. Any other questions? Thank you for your
10 attention.

11 COMMISSIONER GEESMAN: Thanks, Jim.

12 MR. KONDOLEON: Okay, thank you. Steve
13 Munson with Vulcan Power will be making the next
14 presentation. Copies of this presentation are
15 actually in process as we speak, and as soon as we
16 have all those available we'll circulate those to
17 the audience.

18 MR. MUNSON: Thank you. I'm going to
19 run through some things very, very quickly. The
20 industry overview today, the new supplies as we
21 see it for California, with transmission cost
22 estimates. And then we've got basically a working
23 group we're setting up for projects that aren't
24 covered by the, what looks like good work with the
25 Imperial working group.

1 We've got three specific projects which
2 have both unidentified constraints and have need
3 for policy decisions. We're not saying that
4 either the CEC or the CPUC can solve these
5 problems, but we're trying to identify the big
6 picture problems that affect geothermal projects
7 for our company and other companies that we're
8 aware of.

9 And some of this policy does run into
10 decisions about coal plants, and what they might
11 do to access for renewables. So, I know that
12 there are policy decision differences represented
13 by the people in the room from some of the
14 utilities, but nonetheless we thought we needed to
15 identify these things. I'll try to hit them at a
16 high rate of speed.

17 Geothermal industry today, we all know,
18 2,800 megawatts, about 8,000 worldwide. Over on
19 the picture here, one thing that's interesting, my
20 partner Tony Bingham developed, as President, was
21 co-developer with CalEnergy, president of
22 Caithness, and they developed a 550 million plant.

23 What's kind of interesting about what
24 they did is that you see three separate 30
25 megawatt units here. And that provides an economy

1 of scale. It's something that's often lost in the
2 discussions of what does it cost to do a plant.

3 It may cost quite a bit to put the first
4 plant online at a site, but if you use one control
5 building for three 30 megawatt units and do other
6 things like that you can reduce the cost as time
7 goes on, and that's one of the benefits of
8 expansion of projects.

9 This is an overview, courtesy of the
10 Geothermal Energy Association, of wind at 3,500
11 gigawattt hours, biomass 5,500, and geothermal
12 13,000 in California now. The other slide shows
13 the distribution of market share in the United
14 States.

15 Caithness is at 66, Calpine 44,
16 CalEnergy 16, Ormat 13, and others about 11
17 percent of the market share. That's courtesy of
18 ENEL at a recent conference.

19 This is courtesy of CalEnergy. I hope
20 they don't object to using this slide. It's the
21 best slide I've seen to show the distribution in
22 California just in geothermal power.

23 We all know that 1078 said to try to
24 diversity the renewables systems, and we believe
25 down here at the bottom that there's some points

1 that we hope that everyone bears in mind.

2 We need resource diversity: geothermal,
3 biomass, wind, and of course the CEC is very much
4 on that now. Location diversity: north, south,
5 central counties. And new jobs in distressed
6 rural areas. These are important drivers, they
7 represent, we believe, the legislative intent, and
8 we hope that we end up with a diversified
9 transmission system.

10 The point of this is just to tell you,
11 of course, as everyone already knows, gas prices
12 are very high, 7.50 an mbtu at Henry Hub and the
13 NYMEX three year strip is over \$7.00 an mbtu.
14 Here's a reference for additional data on north
15 American gas supplies and pricing.

16 What we think is important is down here.
17 You know, the MPR next year may be above \$0.07 a
18 Kwh. And that really puts pressure on our
19 renewable system to support, and it also of course
20 gives some cover to the pricing schedule, and it
21 may also help with the public good charge payments
22 that will be required. But we think that MPR may
23 well be above 7 cents next year.

24 So what we're looking to do is trying to
25 get the policy set now to provide at least 1,350

1 MW of new geothermal for startup by 07-11, and add
2 another 1,560 megawatts of geothermal if the 33
3 percent RPS passes.

4 So, again, this chart is courtesy of
5 CalEnergy, and I'm sure it doesn't represent their
6 guarantee of steam supplies for the future in any
7 way, but we use the chart because it came from the
8 other chart and shows you where the industry might
9 be going.

10 2,300 megawatts in the Imperial, and
11 perhaps 500 megawatts up here in Siskiyou County.
12 And, the color's a little hard, but I think 2,200
13 in Shasta and the Geysers area. And then of
14 course Mono and Inyo may expand as well.

15 This slide just talks about the desire
16 to make sure the system is diversified and its
17 resource type. This is, though, this complicated
18 slide is showing you that the neighbor state's
19 supply to California could be very significant.

20 The California Intertie COI is 4,800
21 megawatts approximately. We have a project at
22 Newberry Volcano that was rated to 700 megawatts,
23 it's very advanced, and it could come down to COI.

24 Other projects that may access the COI
25 include the Medicine Lake project, and if you're

1 looking over here, Medicine Lake would be located
2 over here and likely tie into service MT15 from
3 the Medicine Lake site, would go up here to Maline
4 (sp) sub, which is part of COI, and down into
5 MT15.

6 And then there's a little project over
7 here at Surprise Valley that also may want to
8 provide power. So the questions that tend to
9 cluster around COI are, exactly where is the Cal-
10 Iso control area? Does it end down here at Round
11 Mountain? Does it end where the PG&E powerline
12 ends at the California border? Can the Cal-Iso
13 exercise, or others exercise any control or any
14 loading order authority or anything like that?

15 And then, over here, here's the Weed
16 substation near military pass at Shasta,
17 PacifiCorp has that service territory. So we have
18 some issues that we address here briefly. Also
19 there is the distinct opportunity to come out of
20 the Lapine substation and go from Lapine, Oregon
21 up to the north end of the PDCI, and put power
22 very cheaply all the way into LA.

23 So the Pacific DC Intertie is 3,100
24 megawatts. We have some different pricing
25 information that was presented a few minutes ago.

1 Possibly because of the scale that that other
2 project analysis used.

3 But in addition to then the PDCI coming
4 from Oregon to LA there's a tap site that we've
5 been working on for three years that could put
6 500 to 1,000 megawatts of renewables in on a tap
7 to the PDCI, right on the California border.

8 And indeed if the agencies in
9 ?California required that such a tap be inside
10 California it could be sited just inside the
11 California border, if that's what's needed to give
12 authority to do something about that tap and bring
13 a lot of good geothermal in from Nevada.

14 And then finally, north of Lugo, up to
15 Bishop, California, there's a well-known
16 constraint, and the work we're doing over there
17 under an SCE contract we'll describe in a minute
18 could provide some power, but in total it looks
19 like there could be an upgrade of that north of
20 Lugo line, to the amount of 345 megawatts. We've
21 got some cost data that we'll present.

22 So that's the big picture, and in a
23 general way we would suggest that the policy
24 makers would consider looking at a phased program
25 where the assigned California PPA's, the ones that

1 are assigned now, the ones that are coming through
2 say the quarter three 2005, that we have our
3 transmission plans set, to make sure we cover
4 those projects.

5 Second, that the PPA's that are then
6 signed through the end of '06. You know, both of
7 those groups of PPA's will probably be online by
8 2011, so that might be used as a planning matrix
9 to determine transmission policy. And beyond
10 that, if the 33 percent RPS passes, obviously
11 there's going to be a whole new set of issues to
12 deal with.

13 We are, you know, obviously as a
14 developer not in the Imperial Valley, we're very
15 concerned that the Imperial Valley doesn't grab
16 all the market share, just like we were concerned
17 about wind for awhile. And so, we just ask that
18 some reasonable phasing take place to allow a
19 number of projects to come online.

20 And as we said down here at the bottom,
21 we don't know what that proper phase-in size is
22 for the Imperial Valley lines, but we'd just like
23 it to be on the planning docket.

24 Here is our best analysis of the
25 contracts that may come up that will need

1 transmission support. This is derived in part
2 from the GEO rumor mill, which is always active
3 and sometimes correct. At any rate, it would be
4 our view that the COI perhaps could be accessed
5 for 10 percent to 20 percent renewables, to bring
6 power that way.

7 The PDCI in a big picture way, perhaps
8 20 percent of the PDCI go to renewables, 120
9 megawatts could come from Oregon, 500 from a green
10 tap down here.

11 And those numbers kind of correlate to
12 what we think might happen here in new contracts.
13 And, as you can see by California counties and the
14 neighboring states, there's 1,360 of new
15 geothermal. That might be a good planning target.
16 And as the numbers roll out on the new PTA's.

17 And of course if there's a new 33
18 percent rule passed then the number might be
19 something like 1,560. These are just our
20 estimates, I'm sure the other companies will have
21 different numbers.

22 At any rate, oh, there's a better
23 picture of the same chart. We have run some costs
24 from the data we have thus far on relative costs
25 of average megawatt of new transmission.

1 So here's the wind guys. They, of
2 course, suffer in the cost in terms of average
3 megawatt. If we assume they have a 35 percent
4 capacity factor then the numbers run from 845,000
5 down to 674,000 megawatts for the Tehachapi plant,
6 the last copy that we saw.

7 North of Cottonwood, and we can discuss
8 that in a second, that's one of the upgrade
9 projects that we believe needs to take place. The
10 first 45 megawatts -- and this is coming out of
11 Weed, California substation and going down to the
12 Cottonwood substation -- the first 45 megawatts is
13 very close to free, \$22,000 per megawatt. The
14 next 240 megawatts roughly for around \$200,000 a
15 megawatt.

16 North of Lugo project, the phase one
17 refers to constraints that were thought to exist
18 that don't, and that's very inexpensive maximum
19 cost, maximum cost \$44,000 a megawatt.

20 Phase two could be very expensive. If
21 that whole system were upgraded with multiple
22 lines and substations that's a million dollars a
23 megawatt.

24 The PDCI Tap, the tap on the PDCI is
25 about a hundred million dollar project for 500

1 megawatts. And we've got proof of that, I guess
2 as good a proof as you can get, because
3 Electranex, who was the DC consultant for the PIER
4 study, has written a letter that we filed with the
5 PUC.

6 And their letter says that it's
7 technically and economically feasible. \$100
8 million, 500 megawatts, about 210,000. This is
9 not very expensive for new transmission.

10 COMMISSIONER GEESMAN: Steve, could you
11 file that letter in our docket as well?

12 MR. MUNSON: I'd be happy to. Yes, sir,
13 and of course it's actually copied and -- one
14 problem with what we've done here is that we have
15 all the data in here, so I'm going to now speed
16 through the letter itself.

17 COMMISSIONER GEESMAN: Oh, okay.

18 MR. MUNSON: And if you want it filed
19 individually we'd be happy to.

20 COMMISSIONER GEESMAN: No, if it's in
21 here it's fine. It's in our record if it's in
22 here.

23 MR. MUNSON: This is a rough estimate
24 about what a thousand megawatts might cost, and
25 that makes it about 160,000.

1 COMMISSIONER GEESMAN: Where do your
2 cost assumptions come from for north of Cottonwood
3 or north of Lugo?

4 MR. MUNSON: Yes, and I'm, I'll get to
5 that in a moment. In a general way, Commissioner,
6 they come from conceptual studies that were done
7 by the two utilities. Both SCE and PG&E were
8 quite forthcoming in those conceptual studies that
9 were required by the ALJ about a year ago. So
10 that's the source of those numbers.

11 In a general way then, north of Round
12 Mountain, a well-known massive constraint, if
13 there were California-Oregon border renewable
14 operating loading order rulings of some type in
15 some form, giving priority to renewables. What's
16 kind of interesting over her eis the actual,
17 physical cost per average megawatt is zero.

18 Now, as we all know, that isn't what the
19 parties that have the transmission rights will
20 maintain. They'll maintain that there's offset
21 costs or other costs, opportunity costs of doing
22 business.

23 But this could be one relatively very
24 inexpensive way to bring substantial amounts of
25 new renewables. And on the left here, Newberry

1 Volcano, Oregon could be a participant. Glass
2 Mountain, California, again would logically go to
3 the COI, and Surprise Valley.

4 A phase two, if we want to add more
5 renewables from that part of the country, again
6 perhaps zero cost. And then going down from
7 Newberry Volcano down to PBCI to Sylmar in LA,
8 zero cost.

9 Imperial Valley, we don't have those
10 numbers. And it looks like Olson and the
11 participants are doing a good job getting this
12 process unwound.

13 COMMISSIONER GEESMAN: Now, just to be
14 clear, if I understand you correctly, when you're
15 identifying something as zero cost you're assuming
16 then that the operator of that particular line
17 would institute a loading order which gave
18 preference to the geothermal resource on the line?

19 MR. MUNSON: Yes, sir. That wants to
20 get on the line. So perhaps even sets up a
21 reserve.

22 COMMISSIONER GEESMAN: Okay.

23 MR. MUNSON: I'm going to try to flash
24 through the rest of these quickly because they're
25 all written. Our company has 145,000 acres.

1 Geothermal seems to be moving again, and as I can
2 tell you and as the Commissioner knows, since he
3 attended a conference on Wall Street, there's
4 really strong interest from the financial industry
5 now to support these projects.

6 So the projects that get the PPA's and
7 have good projects, they're all going to get
8 funded I think, it looks like it.

9 In general we have projects that could
10 come in across the Pacific AC, the DC, perhaps the
11 Oxbow line in cooperation with Caithness, if that
12 happens. And there's just multiple places. These
13 are the spots showing the identified potential
14 geothermal sites around the west, and there are a
15 lot of them.

16 And this idea of coming into California
17 with geothermal is not new. Caithness is in the
18 room, and here's our Dixie Valley plant, 55
19 megawatts to SCE, 210 mile connector, and I think
20 it's been operating close to 15 years.

21 So our company's got about 50,000 acres
22 over there, and some of them are very similar
23 to --.

24 I don't want to stress this at all, but
25 our company is 15 years old now, we're kind of

1 getting tired, we don't have a megawatt on line
2 yet. This market change with the RPS could drive
3 our company and four or five or six others to
4 success. We do have 120 megawatts of contracts
5 that are signed. We have 330 megawatts in
6 process, not including the 90 that we think we
7 ultimately will get at DWP.

8 We're currently then processing about 11
9 percent of that 4,000 megawatt RPS market. We
10 have knowledgeable partners, Energy Investors
11 ?Fund helped fund Path 15, they have power plants
12 in California. And we have \$150 million of equity
13 term sheets that we're negotiating on now.

14 So -- and I imagine other people are in
15 similar position or better. But we have a very
16 knowledgeable team of people, a well-known group
17 of scientists that are working on our projects
18 now, some of them have been working on them for 10
19 years.

20 Our approach is to supply California
21 from 120,000 acres of properties. We have a very
22 tightly drawn engineering plan, as to what types
23 of resources and why types of power plant designs
24 to get us the most cost-effective power.

25 These are just a quick summary of our

1 three projects. Down here at the bottom -- we all
2 know what AB 970 says, you know, it says get
3 moving on new transmission. And it's time to do
4 that, and right down here at the bottom, we really
5 appreciate the CEC's willingness to address and
6 try to remedy these things now.

7 It's just barely in time. There's going
8 to be a number of projects that need this in a
9 couple of years.

10 We have a regional geothermal
11 transmission working group. We would like to see
12 all the parties join, including other developers
13 that express some interest. In PacifiCorp won't
14 join we would ask that the agencies direct them to
15 join. We haven't seen them be very forthcoming.

16 That's our opinion. I know they've been
17 very active in wind, but they didn't issue a
18 conceptual study request so that we could get data
19 on the transmission like the other guys did.

20 And if DWP doesn't want to participate,
21 we suggest some letters to the senior management
22 down there. And I know that DWP is in the room
23 and may totally disagree with our view of things,
24 but --.

25 At any rate, the purpose is to evaluate

1 three regional transmission upgrade projects and
2 try to have it keyed up so there could be
3 leadership, agency leadership policy by the end of
4 September.

5 These are our suggestions, and one
6 suggestion is to set the regional geothermal
7 supply targets by county and by out of state by
8 the end of September.

9 Implement a COI priority, as we talked
10 about. And we believe this is a renewable policy
11 issue, I know Semptra isn't going to agree
12 probably, but we believe that it's important in
13 some ways to stop the 1,450 megawatt coal plant
14 right on the California-Nevada border from taking
15 47 percent of the PDCI capacity. And in lieu of
16 that support a green tap down on the Nevada
17 border.

18 We also perceive that there's some
19 staffing, that Cal-Iso could use some additional
20 technical staff. That's just, I guess, our
21 opinion.

22 In terms of financing, we would like to
23 see a financing plan come out with two different
24 sets of projects, one in the Imperial Valley and
25 one set of three or four projects not in the

1 Imperial Valley. A financing plan by the end of
2 September for the projects that are going to start
3 coming online in '07 and '08.

4 And, you know, the way it looks to us,
5 having sat through numerous of these meetings thus
6 far, the IOU's that are in the RPS are the logical
7 source of funding, depending on the SCE FERC
8 outcome.

9 If that's not successful, though, to
10 make this work, we're going to have to establish
11 third party project financings like Path 15, or
12 something like that, probably. And if we're going
13 to get that stuff done in time it's going to need
14 to be done by the end of September, this year.

15 You know, our view of DWP isn't the one
16 we'll probably hear today from their staff, but
17 given what we've witnessed with them we'd like to
18 see the consideration of a PDCI green tap finance
19 authority, either for outside the state or in-
20 state, cooperatively with the agencies, and get a
21 tap built.

22 I think that'd be good for California
23 and it'd be good for the industry, and it could be
24 done inside the state of California. We could get
25 the power to it down the big, wide PDCI right-of-

1 way that runs through Nevada.

2 So, a couple of policy questions. How
3 much of the 4,800 megawatt COI AC lines into
4 California should be devoted to new California
5 renewables? 120 megawatts? We think we've got a
6 near-term power contract coming from Newberry, we
7 think. 240 megawatts? 1,000 megawatt? I don't
8 know. No one knows probably, but ten percent is
9 480 and 20 percent is 960.

10 And then how much of the PDCI should be
11 devoted to renewables? Zero? Do we give it all
12 to Sempra coal plant? Maybe 500 megawatts in the
13 2008-2009 time frame? And deliver 120 from
14 Oregon? So then the PDCI is at 20 percent
15 renewable? I don't know.

16 This is a policy consideration. You're
17 probably aware of it, yo may not be aware of how
18 dire it is. But this is the drought picture for
19 the last six years, and there have been abnormal
20 to severe droughts in five of the last six years.

21 PG&E up there is asking what's a normal
22 hydro year? This is serious stuff, and it impacts
23 decisions that you might make on the COI, which
24 impacts our availability as an industry to get you
25 power. So this is something to bear in mind.

1 A few years ago there was 5,000
2 megawatts lost, due to drought. So this is one of
3 our projects. Thank you, running out of time
4 here, trying to leap tall buildings with one bound
5 here, it's difficult.

6 This is, what I'm going to do now is
7 just show you our projects and close it out. This
8 is the project north of Lugo. This is the study
9 that was done for us by Southern Cal Edison. This
10 is the cost estimate in the first phase, very low
11 cost, to bring power down to the control sub,
12 which is north of Lugo, from these projects.

13 The next one is to show you that the
14 phase two idea is to fix all of these lines from
15 Lugo up to control is very costly. It's \$328
16 million, it's a million dollars a megawatt. Might
17 just think about skipping this, and jump into the
18 PDCI, which is the third phase.

19 Here's the letter from Electranex that
20 says it's technically and economically feasible.

21 This is the screening level study that
22 was done for the Military Pass-Shasta project,
23 located here. The data is in here. ?This is the
24 analysis of the cost. It's almost no cost for the
25 first phase and a relative low cost for up to 240

1 megawatts from this area down to Cottonwood.

2 There are multiple developers, we've
3 talked about that, north of Round Mountain. This
4 is the Newberry project in Oregon, 600 fahrenheit
5 steam, ten mile production area, highest shallow
6 temperatures in North America we're aware of, 500
7 degrees at 3,000 feet.

8 This is looking from Medicine Lake 30
9 miles to the flanks of Shasta. This project did
10 get both of its decisions to go forward issued by
11 the federal agencies.

12 So we have then, we close with a lot of
13 reasons to consider closing down or stopping the
14 Semptra coal plant, and I thank you very much for
15 the ability to present to you. Thank you.

16 COMMISSIONER GEESMAN: thanks, Steve.

17 MR. KONDOLEON: Thanks so much, Steve,
18 and again we're in the process of reproducing all
19 of those slides, and we'll get those to you as
20 quickly as we can.

21 Next up we're going to have three
22 discussions with regard to the Imperial Valley
23 area. The first one's going to be kicked off by
24 Dave Olsen. He'll talk about the Imperial Valley
25 Study Group.

1 MR. OLSEN: Good morning. Thank you
2 very much for the opportunity to report on the
3 Imperial Valley Study Group. The Study Group
4 intends to present a recommendation for a
5 comprehensive plan for the phased development of
6 the generation and the transmission to fully
7 utilize the Imperial Valley's geothermal
8 resources.

9 As we've heard this morning, and as also
10 established in this Commission's Renewable
11 Resources Development Report, there's a large
12 concentration of high quality geothermal resource
13 in the Imperial Valley. There's 540 megawatts in
14 operation now.

15 The next plan is 200 megawatts at Salton
16 Sea Unit 6. It's in advanced development and we
17 can expect an online date of early 2008. And
18 there's an additional 2,000 megawatts available to
19 export.

20 The Energy Action Plan schedule for
21 meeting the California RPS would require almost
22 25,000 gigawatt hours a year of new renewables in
23 2010, or over 30,000 gigawatt hours in 2017.

24 2,000 megawatts of additional Imperial
25 Valley geothermal would generate 16,000 gigawatt

1 hours per year, so a very appreciable percentage
2 of that RPS requirement.

3 The California Public Utilities
4 Commission found in its Tehachapi decision that
5 accessing the large concentration of wind resource
6 in that part of the state cost effectively could
7 require building transmission in larger
8 increments, with each increment capable of meeting
9 the transmission needs of several years of RPS
10 winning bidders.

11 That decision also directed the
12 Tehachapi study group to consider whether such a
13 planning approach should be used for other
14 renewable resources areas of the state, including
15 the Imperial Valley.

16 As a result of that, the Tehachapi study
17 group formed a committee to explore transmission
18 access for the Imperial Valley and asked me to
19 chair that effort. Simultaneously this
20 Commission's Integrated Energy Policy Report has
21 called attention on several occasions to the need
22 to develop generation and transmission to access
23 Imperial Valley geothermal resources in a
24 coordinated and expedited way.

25 That is the background for the formation

1 of the Imperial Valley Study Group, which is
2 identifying transmission solutions capable of
3 physically, reliably, exporting 2,000 megawatts of
4 geothermal power in a phased plan extending over
5 several years with consolidated permitting.

6 This is to be based, to the extent
7 possible, on a consensus recommendation of
8 affected stakeholders, in the interest of creating
9 enough support for the development of this
10 transmission to overcome the inevitable opposition
11 to the siting of new transmission.

12 This plan that the Study Group is
13 working to prepare will ensure reliable operation
14 of the grid, with these transmission additions,
15 and it will be a least cost plan, a least
16 environmental impact plan. It will propose the
17 phasing of the development of the generation and
18 the transmission, and will propose triggers for
19 each phase, for both the permitting and approval
20 work and the construction work.

21 It will include a strategy for
22 permitting the entire multi-year phase
23 development, and may include recommendations of
24 CPCN applications or similar proposals to public
25 power boards of directors.

1 It will address cost responsibility
2 issues, and cost recovery, and will certainly
3 present a plan for joint operation of the
4 facilities between the Imperial Irrigation
5 District, the publicly owned utility, and the
6 California ISO.

7 Another important outcome of the Study
8 Group effort is advocacy for the actual
9 development and construction of these resources.
10 So the Study Group is aiming beyond recommending a
11 plan to the implementation of such a plan,
12 consistent with the needs of California RPO's.

13 The participants include the
14 transmission owners and operators, and there are
15 quite a number that are affected by flows in this
16 region. They include, in addition to the Imperial
17 irrigation District system and the San Diego Gas
18 and Electric system, Southern California Edison,
19 the Western Area Power Administration, the US
20 Bureau of Reclamation -- which owns transmission
21 in that region --, Arizona Public Service, and the
22 Commission Federal de Electricidad in Mexico.

23 There are several potential power
24 purchasers. The Salt River Project, Arizona
25 Public Service, Western Area Power Administration

1 for example have all expressed interest in
2 considering the purchase of geothermal resource
3 from the Imperial Valley.

4 Cal Energy and Ormat represent
5 geothermal developers active in this effort.
6 There are many county, state, and federal agencies
7 that will be involved in permitting these efforts,
8 and the Study Group is making a great effort to
9 involve all of them early.

10 The California Energy Commission and the
11 CPUC are both involved, as are several
12 environmental groups.

13 The Study Group has set ground rules for
14 working collaboratively together. Minutes of each
15 meeting are reported and approved by all; the
16 planning assumptions are transparent; data is
17 shared subject to WECC confidentiality
18 requirements; and the participants have all agreed
19 to make a good faith effort to reach consensus on
20 key issues. In order to enable the Study Group to
21 present a plan that represents a consensus, to the
22 extent possible of all these stakeholders.

23 If it turns out that consensus is not
24 possible on all points the dissenting parties can
25 certainly file a separate report.

1 So far the work of the Study Group has
2 focused on technical transmission planning
3 studies. It's been led by a technical work group
4 which has been undertaking power flow and dynamic
5 studies and will proceed to do some production
6 simulations.

7 As we're nearing completion of the first
8 round of power flow studies, we're in the process
9 of forming a steering committee to guide this
10 effort from here on out. The steering committee
11 will take up the issue of how best to phase the
12 development of both the generation and
13 transmission, the permitting work necessary, the
14 ownership and operation issues, and the funding
15 recommendations.

16 We're also in the process of forming a
17 permitting work group, which will involve the many
18 county, state and federal agencies, to design a
19 permitting strategy for the entire project.

20 The technical work group, which has been
21 underway now since the fall, includes all of these
22 entities. The Imperial Irrigation District and
23 San Diego Gas and Electric have really taken the
24 lead and done an excellent job with their very
25 capable staffs with the design of the power flow

1 studies.

2 The ISO, Southern California Edison,
3 Arizona Public Service, Western, the Metropolitan
4 Water District, the CFE and CalEnergy are also
5 active participants in these technical
6 transmission planning studies. Some of the border
7 generation group, notably Shell Gas and Trading
8 and Corum (sp?) are actively involved and come to
9 every meeting.

10 I want to emphasize that this
11 transmission planning work has been closely
12 coordinated with the SDG&E 500 KV study. There is
13 significant overlap between the transmission
14 solutions that the Imperial Valley Study Group and
15 the SDG&E 500 study are undertaking, and the two
16 studies are synergistic in many ways.

17 All of the people in the regional
18 transmission owners that are reviewing the SDG&E
19 500 KV study receive all communications from the
20 Imperial Valley Study Group, so there is a
21 material tie here between the two efforts.

22 The Imperial Valley Study Group also
23 reports to STEP, the Southwest Transmission
24 Expansion Project, at every meeting, to keep all
25 of the regional interests fully informed in the

1 details of the study plans that we are undertaking
2 to make sure that we leave nothing out in our
3 consideration of the power flows and the delivery
4 of the power that we are considering.

5 Schedule. We identified several
6 possible transmission solutions to move the power,
7 to make this Imperial Valley geothermal power
8 accessible to regional markets. We did that in
9 the fall of last year. We developed base cases
10 using the WECC 2014 approved cases for heavy
11 summer, developed a similar case for light autumn,
12 and we have now nearly completed power flow
13 studies on the transmission alternatives against
14 those base cases.

15 So we understand now the delivery
16 impacts at certain key points. As a result of
17 that work we are able to narrow the number of
18 alternatives we'll consider going forward. We'll
19 begin dynamic studies on a narrowed set of
20 alternatives next month, and will complete the
21 production simulations in May and June.

22 The production simulations should help
23 us to rank these alternatives in order to make a
24 final recommended transmission plan. With our
25 final report having a target date of the end of

1 June.

2 We have a meeting tomorrow at Semptra in
3 San Diego. Meetings and all of our work documents
4 are available on the Imperial Valley Study Group
5 website. It's on the Energy Commission website,
6 it's right there. And it's a good way to track
7 our progress and get notices of meetings.

8 That's the end of my presentation, I'd
9 be happy to take any questions.

10 COMMISSIONER GEESMAN: Thanks very much,
11 Dave, we very much look forward to seeing the
12 report in June.

13 MR. KONDOLEON: Okay, next we're going
14 to have a presentation from the Imperial
15 Irrigation District, IID. They'll be talking
16 about their Green Path Initiative. Frank Barbera
17 is here to provide that presentation.

18 MR. BARBERA: Good morning, members of
19 the Commission, members of the general public. My
20 name is Frank Barbera. I'm very proud to discuss
21 with you IID's proposed Green Energy Path.

22 The Green Path is a transmission
23 corridor that provided access to many of the
24 control areas within the Western Interconnect to
25 the rich geothermal energy resources within the

1 Imperial Valley.

2 What you see here before you is the
3 geographical representation of IID's control area.
4 The geothermal resources are pretty much centered
5 south of the Salton Sea in the heart of the IID's
6 control area.

7 We have transmission corridors that
8 exist around the geothermal resources. IID energy
9 is a controlled area, and we are interconnected to
10 other control areas, primarily Cal-ISO, through
11 Edison, through the northwest corner; the San
12 Diego Gas & Electric, through the new proposed
13 interconnection at the San Filippi substation;

14 we are interconnected and have corridors
15 to Western Area Power Administration, in the
16 northeast corner through to Blythe, via our Buck
17 substation; and to Arizona Public Services
18 controlled areas, the southeast portion, Pilot
19 Knob substation, within our control area.

20 What you see here is a plan that allows
21 us a lot of path and right of way for future
22 expansion. It offers redundancy, or additional
23 reliability, in order to bring the geothermal
24 energy to the points of interconnection.

25 What really needs to be done to get the

1 geothermal energy to the Western Interconnection
2 is to have collaborative efforts between all the
3 load-serving entities, all the transmission
4 owners, all the renewable energy suppliers, so
5 that we can achieve the maximum economies of
6 scale.

7 We need to, in doing this, implement
8 joint transmission projects that are not just for
9 renewable energy supplies, but also for other
10 energy needs as well, both present and in the
11 future.

12 What we're looking for is to ensure that
13 a regulatory environment exists that allows
14 entities with different models, primarily the
15 financial models and the physical models, right to
16 co-exist and jointly participate in new
17 transmission projects.

18 This may require modification to
19 existing tariffs and regulations, but it will
20 allow price and operational certainty to those
21 entities that need it.

22 Without a collaborative effort on energy
23 and transmission, the development of the
24 geothermal resources will be impaired. Upgrades
25 and interconnections with other control areas will

1 be small and incremental. The economies of scale
2 will disappear.

3 IID's position is this: we're willing
4 to step up to the plate, to be the lead agency to
5 coordinate the various efforts within the Western
6 Interconnect to promote the Green Energy Path.

7 We are working with other various
8 transmission planning organizations, STEP, the
9 Southwest Area Transmission Group, the Colorado
10 River Transmission Group, CEERT, IVSG. They all
11 presently have incorporated the Imperial Valley
12 geothermal into their footprints.

13 We're working, we want to promote joint
14 transmission projects between all of the control
15 areas, all of the IOU's, all of the public
16 utilities, the independent power producers, all
17 load serving entities, as well as independent
18 transmission providers.

19 And we're looking to develop
20 collaborative efforts to identify and mutually
21 resolve the obstacles to Green Path
22 implementation.

23 We will solicit unified support from the
24 various entities and common problem resolution.
25 Those agencies that we want to work with are, of

1 course, the CEC, the control area network
2 discussion organization group -- which we are a
3 member of.

4 We want to work with Cal-ISO. We are
5 involved on the geothermal and transmission work
6 groups of the Western Area Governors Clean Air and
7 Diversified Energy Advisory Committee. We're of
8 course involved with CEERT. We're working with a
9 number of the transmission owners and control
10 areas that are involved with west connect.

11 We are working with all of those in the
12 west connect that are involved with the west trans
13 Oasis site, and that would be not just the
14 transmission providers but also multiple customers
15 as well.

16 We are working with the public powers
17 initiative of the west, a group of public power
18 transmission owners and control area, to resolve
19 some of the issues that exist between the control
20 areas within the Western Interconnect. And we are
21 also working with FERC, other state PUC's, as well
22 as other state governing bodies.

23 That's where our efforts are
24 concentrated. I would entertain any questions at
25 this time.

1 COMMISSIONER GEESMAN: Thank you very
2 much for your presentation. I wonder if you've
3 given any thought to the, in terms of joint
4 projects, what limitations the tax code places on
5 your use of tax-exempt financing in engaging in
6 any projects that might be jointly sponsored with
7 private entities?

8 MR. BARBERA: What we would do is, in a
9 transmission project, from IID's point of view,
10 just solicit enough transmission to support our
11 load serving needs. The advantage of having joint
12 projects helps build up a more robust transmission
13 system through the IID network.

14 So, actually we're looking at
15 participation in joint projects that would be in
16 the form of transmission ownership rights of any
17 other entities that might be looking to
18 participate. So it really wouldn't impact our
19 tax-exempt status.

20 COMMISSIONER GEESMAN: Your belief is,
21 then, that you could finance the portion of a line
22 that was intended to meet your own load needs, and
23 that a private party could finance the other
24 portion of the line?

25 MR. BARBERA: That is correct.

1 COMMISSIONER GEESMAN: Thank you. Is
2 there any thought given to, I don't believe I
3 heard any reference to green energy possibilities
4 south of the border?

5 MR. BARBERA: Presently no, that's not
6 within our radar scope. We've talked to CFE,
7 whether there was any interest there. They have
8 indicated to us that they have a lot of geothermal
9 energy south, but they were using it for their own
10 needs, per se.

11 COMMISSIONER GEESMAN: One last question
12 as it relates to the proposed F line. Is that
13 still under consideration as a prospective permit
14 application?

15 MR. BARBERA: Yes it is.

16 COMMISSIONER GEESMAN: Okay, so that
17 would go from midway to the Buck substation?

18 MR. BARBERA: Yes, that's where it is
19 proposed. There are some concerns that we have
20 about doing upgrades on that, but we're following
21 through with the regulators pursuing that, and
22 with the military involved.

23 COMMISSIONER GEESMAN: Thank you.

24 MR. BARBERA: Any other questions? All
25 right, thank you.

1 MR. KONDOLEON: The next presentation
2 will be from Dave Geier from San Diego Gas and
3 Electric. He'll talk about the 500 KV
4 Interconnect Project.

5 MR. GEIER: Good morning, Commissioners,
6 audience. Thank you for allowing me to speak
7 today, actually one of my favorite topics here is
8 transmission and how we connect the geothermal out
9 to Imperial Valley.

10 I had a little, a bit of the past
11 experience of SDG&E with geothermal. We actually
12 have a rich history going back almost 30 years of
13 exploring geothermal resources out in the Imperial
14 Valley.

15 I'll talk a little bit about today, sort
16 of the real world, where our transmission
17 constraints are, and then a little bit about our
18 proposed new project, a 500 KV line that hopefully
19 will allow us to interconnect with some of those
20 geothermal resources.

21 If you look back, in the 70's we
22 actually started some of the exploration out in an
23 RD&D effort with Magma Power. And we looked at
24 drilling some wells in Imperial Valley.

25 And this was some of the early

1 stakeholder-type work. And really that was tied
2 in with the project that we began in the 80's at
3 the Heber binary cycle plant. That was an RD&D
4 plan through EPRI and other folks. We were
5 exploring the potential of using some of the
6 binary cycle to capture some of the resources,
7 lower heat resources, in Imperial Valley.

8 During the mid-80's also we built our
9 one and only 500 KV line, that actually connected
10 us to Arizona and allowed us the time to get
11 resources from Arizona. At the same time we
12 connected to Mexico, which was the first couple of
13 connections to Mexico, one in Imperial Valley and
14 then a connection within San Diego County to
15 Tijuana.

16 So we've been doing a lot of work over
17 the course of almost 30 years, and I think now, as
18 we're in to the 2000's here, we're really now
19 finally to the point where we believe that
20 resources can be commercial and can add
21 significantly to the resources that we need to
22 serve the citizens of San Diego.

23 So let's talk a little bit about some of
24 the benefits and challenges of geothermal. First
25 of all, we agree with almost all the previous

1 speakers, that there's a huge potential for
2 geothermal in the valley, somewhere 1,000 to 2,000
3 megawatts, and that this really is a great
4 renewable resource given its capacity factor, the
5 fact that it's sort of a 724 resource.

6 And if you look at the SDG&E system, one
7 of the things we need in our long-term resource
8 plan is this baseload energy and capacity that
9 will fit into the plan.

10 The other thing that the geothermal in
11 the valley can add, it would be available if the
12 contracts were all in place and as they expire for
13 rec credit also. We talked a little bit earlier
14 about the availability of these resources, and how
15 they're a 30 year resource.

16 I think we've seen that, it's been
17 demonstrated. So really there's long-term
18 benefits to the geothermal resources.

19 Now, challenges. We've talked a lot
20 today about transmission. That truly is a big
21 constraint, and SDG&E is proposing our 500 KV line
22 that will help get some of that power to San
23 Diego.

24 In Frank's presentation, we applaud the
25 efforts of IID and their Green Path in the valley.

1 Really we believe that, working in conjunction
2 with IID, we can get a path that not only will
3 allow our energy to come to San Diego but to Los
4 Angeles and, as Frank talked about, really to the
5 whole southwestern United States.

6 One thing we talked about was cost.
7 We've seen lots of numbers today, and with the
8 standards in California, most of that again is
9 tied to energy, and I think we probably need to
10 put a little more emphasis on how the availability
11 of that resource is treated also.

12 That you start comparing geothermal to
13 wind, wind -- as we saw last year during system
14 peak -- a very small percentage of that wind was
15 available. But all that can be taken care of if
16 we just get the price signals right. So I think
17 that's a key thing we need to do in the future.

18 And again we have to have a commitment
19 to the environment. I think that's been shown in
20 the Imperial Valley, and that will continue to be
21 an issue.

22 Commissioner Boyd, your question about
23 Mexico. We've been exploring Mexico also. CFE
24 has indicated that most of their future
25 development there will be for their needs, but we

1 feel that there is a huge potential for geothermal
2 south of the border also.

3 But we'd also be committed to making
4 sure we meet the environmental standards that we
5 have for those plants also.

6 What is our goal? SDG&E is committed to
7 providing 20 percent of our energy by 2010 from
8 renewables. ?This will be a challenge. And
9 without the 500 KV line it's a significant
10 challenge.

11 There are significant renewables within
12 San Diego County, but quite honestly without
13 stepping out to Imperial Valley it's going to be
14 very difficult to meet our 20 percent goal.

15 Even within San Diego County, it's
16 interesting, to deliver the wind it's also in an
17 area that's lacking transmission today, and to get
18 any significant amount of wind from within San
19 Diego County we need new transmission there also.

20 And if we had amounts in the hundreds of
21 megawatts, we no longer can just upgrade existing
22 lower voltage transmission lines, we have to start
23 building high voltage transmission lines, so that
24 adds up to additional licensing and regulation
25 that we're going to have to work through.

1 So the transmission constraints we're
2 talking about. Currently we do have the one 500
3 KV line we call our southwest power link. We have
4 the lines that go to Mexico. All of those today
5 terminate at our Miguel substation, which is on
6 the eastern part of San Diego County. It's the
7 western terminal for the southwest power link.

8 This particular substation, 500 KV
9 substation, has been one of the most congested
10 substations in the west, definitely within the ISO
11 service territory. We've been working hard over
12 the last couple of years to upgrade that.

13 Last year we upgraded the substation
14 itself. We put in parallel transformers. We now
15 have the capacity up to about 1,500 megawatts.
16 And we're currently today building a new outlet to
17 a 30 KV transmission line that will bring the
18 capacity up to the 18 to 1,900 megawatts.

19 So we will have almost 2,000 megawatts
20 over that one transmission line. And even though
21 it does meet all the WECC and the NERC reliability
22 standards, San Diego's peak is about 4,000
23 megawatts.

24 So whenever that line trips out, which
25 it has a history of doing due to fires, due to

1 contamination, due to gunshots, you know, this is
2 a transmission line that's over 100 miles long
3 going through the desert, so there's lots of
4 opportunities for people to either take the line
5 out with a gunshot or just weather conditions.

6 So we have a lot of eggs in one basket
7 there, and we believe that the new 500 KV line
8 would give us additional reliability also. And in
9 fact by 2010 it's needed for reliability.

10 COMMISSIONER GEESMAN: Dave, when do you
11 see the Miguel mission line coming on?

12 MR. GEIER: We have recently updated the
13 PUC and told them that line will be of service in
14 July of this year. We filed a petition for
15 modification, as you're probably aware of, in
16 December of last year, and we said we thought that
17 we could do it by September.

18 We sort of realized the situation the
19 state's in this summer, we've accelerated it up,
20 and we will have it in service in July.

21 COMMISSIONER GEESMAN: That will be very
22 helpful.

23 MR. GEIER: This is just a picture of
24 our transmission system, and again the 500 KV line
25 is shown in red. And, as we look at San Diego we

1 really only have the one line coming from the
2 east, and more than two or three lines coming from
3 the north.

4 And for those that are familiar with San
5 Diego, it's almost like having a highway 5 and a
6 highway 8 with no highway 15. And one of the
7 potential routes for our new transmission line
8 will bring us in that highway 15.

9 A lot of our load growth has been
10 throughout the northwestern part of our county,
11 and right now that's all served by lower voltage
12 transmission.

13 The need is one thing that we've been
14 looking at for our 500 KV line. As Dave alluded
15 to, we're working in a collaborative effort with
16 the STEP group, the IV planning group -- there's
17 really three drivers for this line, the first is
18 reliability.

19 As I mentioned, in our long-term
20 resource plan we've cited 2010 when we actually
21 need the line to meet reliability criteria.
22 That's sort of the hard criteria, as I mentioned.

23 From a softer point of view, and sort of
24 as the operator of the transmission system, it
25 makes me very nervous to see the load growth

1 that's happening to San Diego over the last five
2 years, and really we haven't added a new
3 transmission line since the mid-80's.

4 So we have the reliability concern.
5 Obviously what we're talking about today here is
6 the connection to geothermal and all other
7 renewable resources. That's a huge interest to
8 us, and as I mentioned, we will have a very, very
9 difficult time meeting this 20 percent if we don't
10 have this transmission line.

11 And a third piece is the congestion
12 piece. Currently, today, because of the lack of
13 transmission and the aging plants in San Diego,
14 our customers are paying \$200 million a year in
15 congestion costs. And we feel, sort of through an
16 integrative plan where we add more generation and
17 more transmission we can reduce that number
18 significantly.

19 So really what we're looking at is a
20 need which is a little bit non-traditional.
21 Traditionally the need has really been tied to
22 strictly reliability, but we're looking at a
23 reliability need, an economic need, and a
24 connection to renewable energy.

25 As Dave alluded to, the studies are not

1 all done yet, but they're coming together pretty
2 quickly here in the June time frame. I think we
3 started out with 14 different options for bringing
4 a new voltage transmission line to San Diego.

5 We've looked at the Imperial Valley
6 line. The big advantage there is the
7 interconnection to these renewables. There's a
8 northern line that would connect our service
9 territory directly to Edison. That would be,
10 there's actually the Lake Elsinore pump storage,
11 that is being studied.

12 We've looked at completing a loop that
13 would go all the way from Imperial Valley and then
14 tie into Edison north. It gives a lot of
15 opportunities there for power flow for the entire
16 southern California area. And one of the options
17 we've looked at is upgrading the transmission
18 system in Mexico.

19 And I commend the groups also for all
20 their efforts. The net was cast quite broadly,
21 and we're sort of narrowing those options right
22 now.

23 I think I've probably hit most of this
24 slide. The stakeholder group, as Dave alluded to,
25 is quite broad. And we're committed to the

1 stakeholder process as we get into more of the
2 licensing phase of the project, which hopefully
3 will be this year, we'll bring the parties that
4 maybe aren't at the table now, or at least with a
5 strong voice, we plan to work with the
6 environmental groups and other folks that have an
7 interest in the line.

8 SDG&E wants to build a new line, we
9 don't want to force a line down anybody's throat.
10 And obviously we know that that's always a
11 contentious issue, but we plan to work with all
12 the folks there.

13 Long term, from a state perspective, I
14 think that what we're looking for there is the
15 agencies to work jointly, the approval process
16 today is pretty cumbersome as far as sometimes we
17 have to prove need in two or three different
18 venues. We need to streamline that.

19 I think that the time is now, I think
20 that the Governor is behind us on this. So we
21 feel that, with all the agencies working
22 cooperatively together also, we can get this
23 licensing process moving forward.

24 And again, we're committed to the sort
25 of local outreach also. We believe that we need

1 to put a line in place that meets the needs of the
2 citizens of San Diego.

3 So what must we do to move forward? We
4 need to work together in this stakeholder process.
5 It's coming together quite nicely. We need to
6 just really pull that together and get that
7 finalized this year.

8 We're committed to work with other
9 folks, and we do plan to file an application as
10 soon as possible. One thing that's sort of
11 unclear at this time is, historically you sort of
12 have everything lined up before you file the CPUC,
13 all the environmental work.

14 We're not so sure that's the route to
15 go. We're fully committed to meeting all the
16 environmental requirements, but it seems like this
17 world is so dynamic, to have everything lined up
18 before you get the process started doesn't quite
19 seem the right way to us.

20 So we'll be proposing to submit
21 something soon that will, as soon as the study
22 groups are done, that will at least get the clock
23 started hopefully, and show out intent to build
24 this new line.

25 And again, we have a website also for

1 our new line. There's a lot of information that
2 Dave alluded to from the other study groups tied
3 into that line also.

4 So, that's the end of my presentation,
5 I'd be happy to answer any questions.

6 COMMISSIONER GEESMAN: Thanks very much,
7 Dave. Needless to say, your company's certainly
8 got out attention, and I think these subjects will
9 be a prominent feature of our strategic plan for
10 transmission this year, and for the IEPR report
11 itself.

12 MR. GEIER: Thank you.

13 AUDIENCE: What's your estimated early
14 as possible realistic timeframe and latest --
15 (inaudible).

16 MR. GEIER: That's a good question. If
17 you look from an economic point of view, as I
18 mentioned, we could use it today, actually.
19 Realistically, probably the earliest is, you know,
20 it's a couple of years to build the line, probably
21 at least a year to actually go through the
22 licensing process, so probably the very earliest
23 you're looking at the 2008 time frame.

24 On the outside, going the other way,
25 historically these lines have been sort of

1 justified based on a reliability need. We
2 realize, in today's environment, things change.
3 If a plant would come on and get licensed in San
4 Diego it may push the reliability need out.

5 So, what we're saying is reliability is
6 one part of this, but with the economic and the
7 connection to the renewables, we still think that
8 2010 is still the more realistic date.

9 That could move out somewhat, we hope it
10 doesn't move out because of licensing time frames.
11 But again, if we have the other two drivers, the
12 economic in connection with the renewables, we
13 think that 2010 is a pretty solid date.

14 COMMISSIONER GEESMAN: I want to jump in
15 there as well, because I have, and this Commission
16 has expressed, an ongoing frustration with the way
17 in which reliability criteria are used to suggest
18 that somehow state government can optimize when
19 this type of resource comes on line.

20 And I think later, in our review of the
21 electricity resource plans that have been filed
22 with us, we will get fully engaged in questions
23 about inside the load center generation resources
24 versus imports from outside the regions via a 500
25 KV line.

1 But I'm fairly frustrated about the
2 implied precision of our ability to achieve a
3 perfect landing as to when a project of this sort
4 is energized. I think that we're likely to be in
5 circumstances where we do the best we can. We
6 recognize an asymmetric risk, where the risk of
7 under-investment is significantly greater than the
8 risk of over-investment.

9 And where the risk of a resource not
10 being available in time is significantly greater
11 than the risk of a resource being online a year or
12 two early. And I want to lay out a marker. I
13 expect that concern to be something that we visit
14 several times over the course of the next six
15 months as the Commission struggles to process some
16 of the issues raised by the utility resource
17 plans.

18 MR. MUNSON: It might not be fair to ask
19 you, because I don't know what you know about that
20 coal plant in Nevada, but there's an interesting
21 possible symmetry here, I think.

22 Is it possible that this line coming
23 online with significant geothermal from the
24 Imperial Valley would decrease the company's
25 enthusiasm for the coal plant up in the

1 California-Nevada border, or are you planning to
2 bring that coal via generation (inaudible) --.

3 MR. GEIER: First of all, I cannot
4 comment on that. I know very little about that,
5 that's a Semptra project. I think one of the
6 things that will actually come out of this whole
7 study will be what does this line do for
8 conventional power also, in addition to renewable?

9 Because I think, if we build a 500 KV
10 line and we add 1,000, 1,500 megawatts of
11 capability, and we still have to be realistic, you
12 know, out there in Arizona there's 8,000 megawatts
13 that wants to come to California also.

14 I think with Frank's work at Imperial
15 Valley there will be opportunities for all power
16 to flow on this grid we're talking about building.
17 Even the frontier line, all of that will sort of
18 come down and tie into the area.

19 So all this really is a network, and it
20 all ties in together. As far as you're specific
21 question about the coal plant that Semptra's
22 providing, I don't really have any specific
23 information on that.

24 MR. OLSEN: One of your earlier slides
25 made a comparison, or made a statement about the

1 cost of geothermal visavis other renewables. I'm
2 a little sensitive on that point, because in my
3 presentation I mentioned that we averaged in
4 things that would probably be uneconomic so we
5 could come up with these average values similar to
6 \$100 per kilowatt.

7 Could you elaborate a little bit on what
8 you were intending in that slide as far as
9 comparison to geothermal -- (inaudible).

10 MR. GEIER: I really can't speak too
11 much to that. Again, that's sort of outside my
12 area of expertise. But I know that if you look at
13 some of the numbers that come in, that people put
14 together, the capital cost of wind is
15 significantly less than geothermal.

16 Now, again that does not take into
17 account this capacity issue. So all that has to
18 come together. It just seems like, on the
19 surface, in the way that the RFO's are being
20 evaluated today, that this cost is a concern. And
21 I just wanted to raise that publicly, if you will.

22 And I think in general if you look at
23 the numbers compared to traditional resources,
24 obviously they're higher also. But, you know, as
25 we go forward we want to make sure that we get the

1 price signals right. That's my real point here.

2 And what's best for the region, and
3 we're looking at energy, and we have sort of the
4 availability issue also. And all that just has to
5 come together so that we get the right price
6 signals out there.

7 MR. OLSEN: My point is, I agree with
8 you, availability has to be taken into account,
9 and when you're looking at a 35 percent
10 availability for wind versus 95 percent
11 availability for geothermal, it's easy to come
12 away with the wrong impression, from my point of
13 view, as far as the cost of geothermal.

14 Because there are projects out there
15 that are available for under the average, and we
16 should keep that in mind.

17 MR. GEIER: Oh, I would agree with that.

18 COMMISSIONER GEESMAN: Thanks, Dave.

19 MR. KONDOLEON: Okay, the final
20 presentations are actually a joint presentation
21 with Elaine speaking on behalf of staff regarding
22 the work on strategic value analysis, and that
23 will be followed up by a presentation on
24 interstate transmission capability by one of our
25 principle consultants, Ron Davis.

1 MS. SISON-LEBRILLA: Good morning. I'm
2 going to talk a little bit about the strategic
3 value analysis, and to give you a little
4 background of how that developed and what we have
5 done with respect to geothermal.

6 I will also have Ron Davis, who has done
7 the transmission aspect of the strategic value
8 analysis, talk about what we've done with respect
9 to geothermal and the transmission analysis.

10 A little background on the strategic
11 value analysis, or -- we call it SVA for short.
12 In 2002 the PIER Renewables Program undertook a
13 project that has become known as SVA.

14 The SVA was to guide the programs'
15 effort to fund renewable electricity generation
16 and research development and generation efforts.
17 After the passage of the renewable portfolio
18 standards the SVA was thought to possibly be of
19 assistance in California's RPS implementation.

20 The SVA was envisioned to be a tool to
21 provide a logical approach to integrating more
22 renewable energy generation into California's
23 electricity system, while simultaneously providing
24 non-energy benefits. For example, environmental,
25 economic, etc.

1 It is a multi-phased effort combining
2 renewable resource assessment, state-of-the-art
3 power flow analysis, filtering criterias to
4 identify a set of priorities and sites with IGIS
5 platform.

6 So, SVA today. What we have done is we
7 have identified, quantified, and mapped
8 electricity system needs out to 2017 with respect
9 to capacity, reliability, and transmission. And
10 Ron Davis is going to talk more about this a
11 little later on.

12 We've selected the years 2003, 2005,
13 2007, 2010 and 2017. We've identified and mapped
14 out geothermal resources, as well as wind, solar,
15 biomass, and some small hydro and ocean.

16 We've projected environmental costs and
17 generation performances for some of the renewable
18 technologies through 2017. Our projections were
19 developed by staff and cooperated by work done by
20 EPRI and NREL and Navigant.

21 We've tried to do the study combined
22 with GIS and economic analysis to try to obtain a
23 best fit least cost approach. And understand that
24 the entire SVA project was intended to develop
25 research development and demonstration targets to

1 help drive forward renewable technologies capable
2 of achieving identified benefits with respect to
3 environmental and to health and safety and
4 reliability and economics.

5 What we will talk about today is the
6 identification and quantification of resources,
7 and that actually was covered very well by
8 Geothermex's Jim Lovekin, so I'm just going to
9 refer to his work. We've modeled the addition of
10 some new geothermal resources on to the grid, and
11 Ron Davis is going to talk a little bit more about
12 that.

13 The geothermal SVA team was consisting
14 of CEC staff, Geothermex did the geothermal
15 resources estimate. McNeil Technologies, in
16 addition to the CEC staff, worked on the costs of
17 the renewable energy technologies. And Ron Davis
18 from Davis Power Consultants, Anthony Engineering
19 and PowerWorld were involved in the transmission
20 modeling aspect of the SVA.

21 What we've done is we've identified the
22 types and amounts of geothermal that can help to
23 resolve hot spots. And Ron Davis will talk about
24 hot spots a little bit later on. Some of the
25 geothermal data was really not usable because it

1 was not transferrable to a geographic information
2 system platform, so we did that.

3 We funded the Geothermex resource
4 assessments, and identified and quantified
5 resources in California and Nevada, but we focused
6 primarily on California. And we transferred all
7 of that information onto a GIS format.

8 This is just a visual comparison. The
9 map on the left is NREL's resource map of
10 geothermal resources in California. On the right
11 is basically the KGRA's that we focused in with
12 respect to Geothermex's work.

13 Identification and qualifications was
14 done by Geothermex, they have a much better map
15 than I do, and this was the draft data, so his
16 data that Jim presented earlier on is the most up-
17 to-date data.

18 And this is just a summary of just the
19 most likely for California that was resulted from
20 the Geothermex's study.

21 And with that I'd like to introduce Ron
22 Davis from Davis Power Consulting, who will talk
23 about our modeling of additional geothermal on the
24 grid.

25 MR. DAVIS: Okay, what we want to talk

1 about is how we came up with doing some locational
2 value. Once we have all this data one of the
3 things we want to do is model the entire state of
4 California transmission system, and then we want
5 to look at a locational value.

6 What we wanted to be able to do is
7 compare different types of renewable resources.
8 In the case of geothermal we have multiple sites
9 that we can look at in the state. Is there a way
10 that we can compare the different resources in
11 their different locations, and give them a value
12 for helping to alleviate transmission overloads or
13 congestion areas.

14 One of the things I'll start off by
15 saying, it was nice to hear the presentations this
16 morning, because they are very consistent with
17 what we have been showing in our report and our
18 analysis that we've been showing. We're coming up
19 with the same things. San Diego was coming up
20 with more 500 KV lines and looking at their
21 congestion.

22 And IID's presentation, where they were
23 looking at having a loop system and having a
24 multiple of the different geothermal sites to look
25 at, which is one of the things that we looked at

1 also.

2 I'm not going to get in to the
3 methodology that we used in determining the values
4 or the comparison factors. I really want to get
5 into showing some of the results we did and how
6 the analysis can be used.

7 Basically, we ran a transmission power
8 flow for the whole state, and we identified where
9 transmission hot spots were. And these could be
10 overloads that occurred due to different M-1
11 contingencies. It could be congestion zones where
12 you have power problems getting in and out of the
13 system.

14 So we came up with a way of weighing,
15 and coming up with a weighted statewide
16 transmission contingency overload value. Now the
17 value doesn't mean that's how many megawatts
18 you've got to put into the system, but it's a way
19 of valuing the reliability of the system so you
20 can compare alternatives.

21 Once we came up with and identified the
22 transmission hot spots then the next thing was to
23 put it on a GIS map so we could overlay with
24 geothermal locations.

25 Our idea was to first try and find

1 geothermal locations that were near transmission
2 problems or congestion areas, and look at the
3 value of installing geothermal there, as compared
4 to building another transmission line or building
5 somewhere where you had to build a large
6 transmission system.

7 This may be a little hard to see, but in
8 this area we're looking at 2010 and 2017. The red
9 areas are the areas where we have the highest
10 problem areas or hot spot areas, and areas where
11 we really should have solving first.

12 As you can see, they're going to be down
13 in the Bay Area, San Francisco, and we also have
14 some problem areas down in southern California.
15 You'll notice that we have some yellow areas along
16 the San Diego coast and some of these, as you go
17 out in time, turn red, and they change in time as
18 you go out from yellow to red.

19 I think this is consistent with what San
20 Diego was saying, in that there is a congestion
21 and some problems that need to be done, but the
22 area needs some additional 500 or some other
23 upgrades into the system to bring the power in.

24 So using this map and looking at the
25 places where the red would be the primary or the

1 best areas that we want to solve first, the yellow
2 triangles are areas where we want to look at a
3 secondary or areas that we can improve.

4 The blue areas are areas that, although
5 there might be a high potential for some
6 renewables out there, transmission constraints and
7 transmission problems are going to cause that
8 there may be some major transmission before we can
9 develop into those areas.

10 And a lot of those blue areas that you
11 see over in the west side there, that was talked
12 about before, are areas that we need to have major
13 transmission to get that geothermal development
14 out in those counties down to make them cost
15 beneficial.

16 If I was to look at the geothermal
17 technical potential in these areas, then we can
18 see the areas which we were going to study for
19 geothermal development. And these are pretty
20 consistent with what was discussed before.

21 We have the areas up in the PacifiCorp's
22 area, we have the geysers, we have Imperial
23 Valley, and there's some areas in the Long Valley
24 area that we looked into and considered.

25 If we were to overlay these geothermal

1 locations with our transmission hot spots or
2 suggested areas that we look at for improvement,
3 you'll see that the geysers fit into the area
4 which needs a lot, but there's a lot of problems,
5 or potential transmission problems in the area,
6 and that the geyser's sitting in the middle of the
7 area.

8 We also have the Imperial District,
9 which has a lot of geothermal, and we have San
10 Diego coming along here, so there's a fit to try
11 to do something to solve this area.

12 But you'll notice the ones along, over
13 by this stretch over here, by Hot Springs and the
14 others. They're located far away from where the
15 congestion areas are, and those are the ones I was
16 saying you've really got to look into some major
17 transmission expansion in order to bring those
18 home.

19 And we have those ones up in here by
20 Glass Mountain, Long Valley, Surprise Valley, that
21 are in PacifiCorp's territory, and we did look
22 into how we could bring that power in and what
23 could be done.

24 This is kind of blurry to see, but I
25 just wanted to blow up the southern California

1 area to say there are areas out in the Imperial
2 area that could use some improvements by having
3 some additional geothermal.

4 And I think IID alluded to that by
5 talking about they needed some geothermal to
6 conserve their own load. And if we could get this
7 development to come over into this area, around
8 San Diego up to LA, then that would go a long way
9 to help improve that.

10 These are the sites that we looked at,
11 and their megawatts. Some of these have changed.
12 We did this analysis about six or nine months ago.
13 There's been some revisions to some of the
14 megawatts, they may have changed a little,
15 especially when you get into IID on the geothermal
16 over there in that location.

17 But these are the locations that we
18 studied for PG&E, PacifiCorp, and SCE. And these
19 are the ones that we looked at for Imperial. Now,
20 on Salton Sea we only looked at 1,400 and now I
21 guess they're looking at up around 2,000
22 megawatts, so we were a little low on our
23 analysis.

24 We recently ran a 2,000 megawatt for the
25 expansion that we had used in our analysis came in

1 1,400, and if it held consistent we could still
2 bring it in without any major development.

3 But we believe that some of these areas,
4 like Brawley and some of the other locations,
5 Niland, that have some additional geothermal
6 development, that if you're going to do some
7 things in that area we may be able to develop
8 that, maybe on a shorter time period, to get some
9 more geothermal in. And it fits in to what IID
10 was talking about, their loop, to be able to bring
11 in additional geothermal around the area.

12 Take a quick look at the geysers at Lake
13 County and Sulfur Bank Field. We looked at 143
14 megawatts up there. It's located at the north end
15 of the existing fields.

16 Our analysis showed that there would be
17 one new transformer at Eagle Lake and a new 230
18 transmission line between Eagle Lake and Fulton
19 substations in order to export the 143 megawatts.

20 If we put that transmission line and the
21 transformer in, we can see that if we install 143
22 megawatts at those locations the contingency
23 overload impact drops by 442 megawatts.

24 What that indicates is that, for every
25 megawatt of geothermal that we install, there's a

1 2.9 benefit to the transmission system in reducing
2 transmission overload to congestion. A minus
3 number is the one we're looking for. A plus
4 number, we say, it increases the overload or
5 increases the transmission, reduces the
6 transmission reliability.

7 So this is one of the locations we
8 looked at. If we were to look at before and
9 after, and you can see there's little yellow areas
10 up in here where geothermal fields are, and over
11 here it goes away. So even studying a statewide
12 transmission plan we can install megawatts of
13 geothermal and be able to see it on a map and be
14 able to record its benefit.

15 Now, we looked at the geysers in Sonoma
16 County, and there there was a potential of about
17 300 megawatts. And during our transmission
18 solution, when we first put the 300 megawatts in,
19 we had some overload. So we had to fix them. So
20 we had to put in a couple of more lines to serve
21 this area.

22 So if we put in the 300 megawatts our
23 contingency overload impact is minus 670. Here
24 again, it says for every 100 megawatts of
25 geothermal we install it has a benefit ratio of

1 minus 2 to 1, so it's a really good place to
2 install generation.

3 if we were to do both Sonoma and Lake
4 County the existing transmission system that we
5 propose would be adequate to bring all that in at
6 one time.

7 Here again, these are located in the
8 same area, so that you can see a slight change in
9 the color of the area that we're in.

10 The Salton Sea is an interesting one, in
11 that we only looked at installing 1,400 megawatts
12 at Salton Sea. We did include some 500 KV lines,
13 which are similar to what's being studied by the
14 Imperial geothermal group.

15 We also looked at the problems of
16 getting the 1,400 megawatts over to San Diego, and
17 we looked at having to do some additional 500
18 development to get the power over to San Diego,
19 and maybe even some 230 development that might
20 have to be done.

21 For installing 1,400 megawatts of
22 geothermal over there, our impact ratio is only
23 minus 715, but its benefit ratio is only .61 to
24 one. So, while it's a slight improvement it's not
25 a major one, and I think the major reason for that

1 is the location. It's really located out in the
2 remote Imperial area. We have a long way to go to
3 get to the resources.

4 And I think additional development needs
5 to be done in order to get the power to congested
6 areas. I think San Diego was right in that
7 additional development needs to be done to get the
8 power in to their service territory, and also to
9 get it up to LA and SCE.

10 We didn't spend any more time to analyze
11 it in a lot of detail. We feel that's part of the
12 Imperial Working Group's job to do.

13 We are, or I am attending the technical
14 meetings of the Imperial Working Group, and what I
15 hope to do as they're developing resources is to
16 feed that into our analysis and look at our
17 benefit ratios as they're continuing to develop
18 their alternatives.

19 And then here was before and after,
20 2017. And you can see that, if we develop the
21 Salton Sea area and we build additional
22 transmission, we can do a lot to improve the area.

23 This basically says that the area would
24 improve with adding additional 500 KV lines. We
25 did study also the second Palos Verde transmission

1 line, and an additional expansion to bring power
2 in from Arizona. And then also to get the
3 geothermal over to the load centers.

4 What we haven't done yet is, we've been
5 doing static power flows. We haven't been doing
6 any production costing modeling, and we're
7 encouraged that Imperial is going to do some
8 production costing on that, because I think it's
9 needed to study how the system is operating and
10 how it's performing.

11 We haven't done any real power analysis
12 yet, and we're hoping to do that a little bit
13 later on.

14 And one of the things that we haven't
15 done yet, and we're in the process, and I think it
16 was brought up, was to look at a total
17 integration. We've been studying biomass,
18 geothermal, wind, and solar, concentrated solar,
19 as individual elements.

20 And now what we're doing is we're
21 integrating them all together to come up with the
22 20 percent penetration by 2010. And one of the
23 things we're discovering is when we put in the 20
24 percent the tentative numbers are looking like
25 we're going to have to do additional transmission

1 upgrades to the system.

2 So, because we're bringing all this
3 geothermal or all this renewables in, we will have
4 to do more upgrades to the system, and that's what
5 we're studying right now.

6 COMMISSIONER GEESMAN: More upgrades
7 compared to what?

8 MR. DAVIS: Once we did them
9 individually, we did geothermal, and we did Salton
10 Sea, and we did each one individually, we
11 developed the transmission expansion as we
12 described here. But as we began to load up 30,000
13 gigawatt hours of renewables in a power flow and
14 we look at the megawatts, what's happening is
15 they're going to share the same transmission
16 lines.

17 So when you got the Riverside
18 development of wind, and you've got the Tehachapi,
19 and then you got the Imperial geothermal, and also
20 some of the wind development may occur around the
21 Los Cocinos substation, and when we put all this
22 together we find we're going to be overloading
23 some of the 500 and 230 lines, as it is now.

24 We've been studying them individually,
25 but now they got to share that transmission

1 capacity. So what we're finding is we're going to
2 have to do additional upgrades to the system to be
3 able to handle the flow.

4 COMMISSIONER GEESMAN: Is there a
5 presumption that you're backing down some fossil
6 resource?

7 MR. DAVIS: And that's one of our
8 concerns that we're looking at right now is we are
9 having to back down gas generation in order to put
10 this in, because you're adding a lot more
11 renewables than low growth.

12 And our concern is whether or not we're
13 going to create additional congestion areas,
14 whether our current RMR units are going to be in
15 the right location, that we might have to change
16 where your must run units are.

17 We're looking into the concern about
18 bar, or maybe low voltage problems depending on
19 how we back down and which units you back down on
20 the gas units to be able to provide all this
21 power.

22 And that may be some of the reasons why
23 you have an increase in the overload, that you may
24 be backing down some of the gas and trying to
25 force it over the transmission lines and now

1 you're creating new overload.

2 COMMISSIONER GEESMAN: Thank you.

3 AUDIENCE: I'm seeing this chart
4 projecting 2010 summer peak loads, which I believe
5 you developed for the study. And I'm interested
6 that it says "projected 2010, COI Alturas, 4,800
7 megawatts, 95 percent."

8 MR. DAVIS: That's on a different
9 presentation.

10 AUDIENCE: Yeah, I know it is.

11 MR. DAVIS: Well, I took them from data
12 from the utilities.

13 AUDIENCE: And what's the data though
14 for 2005, 2006, and 2007, can you provide that to
15 interested parties? That's question one.

16 MR. DAVIS: Okay, can we wait until we
17 finish this one --

18 AUDIENCE: Oh, I'm sorry, I thought you
19 were done.

20 MR. DAVIS: And then I'll do the one on
21 the Intertie.

22 AUDIENCE: Sure.

23 MR. DAVIS: Sorry. That's okay. Yes?

24 AUDIENCE: Does your model make it
25 possible to apportion out the reliability added in

1 such a way that it would apportion out the costs,
2 saying that when you add transmission you're not
3 only necessary to deliver renewables but it also
4 makes the system more reliable, if I understood
5 your results?

6 And if that's true can you then take
7 part of the costs of the transmission and count
8 it, you know, count it towards general system
9 reliability and only take the other part and
10 consider that as what the renewable should be in
11 some way charged for transmission expansion costs?

12 MR. DAVIS: That's going to be the next
13 phase, the next part of the project that's going
14 to be done, is to look at how you're going to
15 allocate these costs, and then another portion is
16 yeah, okay, we went through and we're looking at
17 integrating and backing down some of the gas
18 units.

19 But you're right, we need to re-change
20 some of our dispatch to make the numbers that we
21 don't have to build some of these transmission
22 lines. What's the impact on cost as we reduce
23 these gas units down and they're operating at a
24 higher heat rate. And then you've got to look at
25 the NOX.

1 And then there's a whole part of how you
2 allocate the cost to the different resources. And
3 all that's got to be taken into the next part of
4 the analysis. And we haven't even talked about
5 the economics or the costs yet.

6 We just started on the integration last
7 week, so we're just starting on it right now, so
8 it's not done yet.

9 COMMISSIONER GEESMAN: In trying to
10 compile that integrated scenario how do you
11 determine your mix of renewable resources?

12 MR. DAVIS: Well, that's an interesting
13 one. We actually had a meeting last week with the
14 renewable energy group, Drake Johnson, and with
15 the PIER group, Elaine and George and others, and
16 we were looking at the resources that we studied
17 that was for everything -- biomass, wind,
18 geothermal.

19 We tried to figure out what would be
20 available by 2010, and what would be available by
21 2017. And as a first pass we've been trying to
22 work at how much energy is going to get out of
23 each one, how many megawatts are going to be
24 available.

25 And to try to come up with a first pass

1 on do we have enough in area resources to meet the
2 20 percent? Or are we going to have to go outside
3 of California?

4 And so we were just trying to take a
5 first pass at looking at the mix that we would do,
6 but we have it based on when they were going to be
7 available.

8 COMMISSIONER GEESMAN: And do you
9 associate costs with that, are you attempting
10 to --?

11 MR. DAVIS: Not yet, but we will. We
12 have to attempt to include costs in there for the
13 resources and the transmission.

14 COMMISSIONER GEESMAN: It would seem
15 that an awful lot would be driven by what the
16 utilities actually solicited for in their RPS
17 solicitations.

18 MR. DAVIS: Yes. And that's the other
19 part you got to look at is, ours is a
20 demonstration of how you could use this to help
21 you in making a decisions on where to put the
22 renewables in, and then also to look to see what
23 the utilities have planned.

24 I think one of the other aspects is
25 that, maybe is not known yet, is how much is

1 coming that the utilities already have contracted
2 from out of state, and what other contracts they
3 may have coming in that we did not include in our
4 analysis, because we didn't study every little
5 location of wind and geothermal or biomass.

6 But that will have to be taken into
7 consideration as we look to fine-tuning it.

8 COMMISSIONER GEESMAN: Well, it seems to
9 me that what you would be attempting to do would
10 be to replicate what you thought each utilities'
11 least cost best fit solicitation would deliver in
12 each of the years that you studied.

13 MR. DAVIS: Yes, but we're only using
14 this to look at what resources we consider within
15 our mix and our pull, and showing that this is a
16 demonstration, showing some of the potential
17 impacts or ramifications when you do integration
18 of looking at the effect over the entire
19 transmission system.

20 COMMISSIONER GEESMAN: Yeah, but if the
21 utility solicitation isn't for the resources that
22 you have assumed are most likely to be developed,
23 I presume it would produce entirely different
24 results in terms of impact on the transmission
25 system?

1 MR. DAVIS: It could.

2 COMMISSIONER GEESMAN: In terms of
3 modeling constraints on the transmission system,
4 are you principally looking at thermal
5 constraints, or stability constraints, or --?

6 MR. DAVIS: In this part of it we're
7 looking at the N minus one contingency overloads.

8 COMMISSIONER GEESMAN: Okay.

9 MR. DAVIS: As I said before, we didn't
10 look at reactive power, and I think we have to
11 look at that as we start over the dispatch of the
12 units, and especially where they're located on the
13 system.

14 We tried to hold the nuclears and the
15 renewables constant, and we held the current list
16 of RMR units, as defined by the ISO. We held
17 those as not being able to be moved.

18 So, it's just a first pass, and an idea
19 on what to look for and what the impacts are as we
20 start to bring in 31,000 or 30,000 gigawatt hours
21 of renewables.

22 COMMISSIONER GEESMAN: But you would
23 expect the RMR's then to continue your analysis
24 throughout the time period?

25 MR. DAVIS: We haven't gotten that far

1 to make any analysis. I don't have any
2 conclusions on that. We just started last week.

3 COMMISSIONER GEESMAN: Okay,k sorry.

4 MR. DAVIS: And I'll just mentioned
5 that, because I think it was brought up that we
6 needed to look at the integration of all these
7 resources. And it's something that we've just now
8 started, but it's only been a week.

9 AUDIENCE: One question. Do you look at
10 this as an iterative process then, and as more
11 data comes in through, probably CEC staff, that
12 you'll be moving the data along?

13 MR. DAVIS: What I'm hoping will come
14 out of this is that, as renewable locations or
15 people have an idea of utilities, where they want
16 to build, they can come in at the Commission and
17 run the model or have the Commission run the
18 model.

19 And I don't know how that's going to be
20 set up yet. To be able to come in and do your own
21 analysis. So this is not a tool that's going to
22 be ours only, but it will be something that will
23 probably be at the Commission so that people can
24 use it and be able to compare.

25 AUDIENCE: Is this still an open process

1 for the next few months? Will you look at things
2 that I might want to submit?

3 MR. DAVIS: No, because I got to finish
4 up in the next couple of months, and they're won't
5 be any budget to do any more right now.

6 MS. SISON-LEBRILLA: I just wanted to
7 add that we are going to present the results in
8 pieces of the SVA, in two more IEPR workshops, one
9 planned for May the 9th, and one planned in the
10 end of June.

11 So, as we get those funds going and
12 start completing the work, we are going to present
13 it in a public format for comments.

14 AUDIENCE: Just a final question. Do
15 you want comments in writing on where it is now?

16 MR. DAVIS: No.

17 AUDIENCE: You said earlier that your
18 model includes backing down gas, because there's
19 no other renewables added than load growth. And I
20 don't see how that could happen for the state as a
21 whole.

22 MR. DAVIS: Well, when you got 20
23 percent that you got to put in in the next five
24 years, 20 percent of the energy, and the utilities
25 are already meeting their low growth, and their

1 plans already show that they conserve the load and
2 they're not growing at 20 percent, they're only
3 growing at one to two percent per year, so there
4 is going to be more energy, then they'll be more
5 energy and more generation available than will be
6 needed.

7 AUDIENCE: But in addition to load
8 growth there's also retirements.

9 MR. DAVIS: That was factored in. We
10 factored in retirements and additions.

11 AUDIENCE: What you're doing is
12 fascinating and also important, because these are
13 billion dollar decisions that are going to be made
14 in the future as far as what kind of plans to put
15 in and where and so, this model's just extremely
16 valuable, what you're doing.

17 MR. DAVIS: Well, it's a way of looking
18 at the resources, and then also to look at what
19 transmission is needed to go along with the
20 resources. And to look at the timing and what's
21 required.

22 To do the Imperial geothermal
23 development there has to be transmission lines, so
24 which transmission lines do you need right away,
25 what is the timing, the permitting, and those

1 could affect when you have generation coming
2 online. So it's a way of using this to help
3 evaluate the timing of what you're going to need.
4 (second presentation)

5 The last one I want to spend a little
6 bit of time talking to you about is the interstate
7 transmission capability. One of the things we're
8 looking at, and actually I've been working with
9 Electranex on this, is how much we can bring over
10 our existing transmission system today.

11 If we're looking at how much we can
12 utilize on the line today, there are certain
13 issues we need to look at and consider. One is
14 what is the capability of the existing
15 interconnection to import out-of-state resources?

16 And the other question that comes, even
17 if you looked at the 500 KV line or the 500 KV
18 system and we tried to bring in more power, one of
19 the other issues that needs to be looked at is the
20 infrastructure, what I call 230 and below, capable
21 of delivering power, even though we deliver it,
22 say from COI down to Tracy.

23 Can the 230 and the 115 lines be able to
24 handle the additional power flow, or are you going
25 to have to do additional upgrades to the system in

1 order to bring out-of-state resources, or even
2 some of the in-area resources, to the load
3 centers?

4 The other one that we're just beginning
5 to think about is what transmission planning
6 studies and developments need to be undertaken.
7 We're taking a snapshot in time of looking at it.
8 Are we going to have to do some power simulations?
9 What other transmission development simulations do
10 we need to undertake?

11 Given the amount of megawatts that is
12 being projected to be coming to the California
13 border, is California able to reliably and
14 economically import this power? And that comes
15 from how much development do we have to do on our
16 system.

17 Some of the issues that we're trying to
18 get through currently and looking at the
19 interstate transmission, is the loading of the
20 current line.

21 Historically, the transmission
22 interconnections have not been fully loaded to
23 their full rating. Very seldom do you get a full
24 4,800 megawatts coming down from COI. The DC
25 Intertie is rated at 3,300, but how often is it

1 loaded at that, and how much is really available?

2 And given the transmission losses on the
3 DC line, what you bring on in the north may not be
4 what you bring on in the south.

5 However, in the 2010 and 2017 power flow
6 studies developed by the utilities that we use,
7 how much or all of the interconnections are loaded
8 to 90 percent or more.

9 So we have these two issues. One is the
10 historical loading of the lines, and the other is
11 what the utilities are projecting going forward as
12 to the loading of the lines.

13 And in either case there's probably a
14 limited amount of room for importing more power.
15 If I was to look at 2010 summer peak loads, the
16 COI is loaded up to 95 percent based on power
17 flows. The DC line is loaded up to 85 percent.
18 And the Palos Verde-Devers is loaded up to 81
19 percent, and that didn't include Palos Verde two.
20 And the Lugo Victorville is loaded up to 92
21 percent.

22 So, the idea is that this is actually
23 based on power flow studies and power flow
24 analysis data sets we got from the utilities.
25 It's consistent with what I've seen from other

1 power flow studies that we've gotten, and they're
2 consistent with what's been shown from what the
3 Imperial Valley Working Group is looking at.

4 So in their studies this is consistent
5 with what they are using in their base tests.

6 When I said, about the units not
7 operating at their full loading, if this is the
8 total of the AC and DC Intertie capability, one of
9 the things is that, with 4,800 on the COI and
10 3,300 on the DC line, you have a capability of
11 about 8,000, but if I look at the loading that
12 occurred in November, for example, it was only
13 rated at, the available transmission capability at
14 the time was one 4,500 megawatts.

15 And then you can see in yellow how they
16 actually used it. And so, even though the lines
17 are rated at 8,000, you can see there's times of
18 the year when they're not fully available at their
19 maximum capacity.

20 And that's why i think it's going to be
21 important that we not just look at the maximum
22 ratings, but we're going to have to look at
23 seasons and we might have to look at some
24 production costing in order to get a look at what
25 impact this is going to have when we study how

1 much we can bring on the intertie.

2 We're modeling three out-of-state
3 resource groups, and we're looking at the proposed
4 transmission upgrades that may be coming on.
5 We're calculating the peak hour available transfer
6 from the out-of-state groups into California.

7 And what we were accomplishing on this
8 first phase was to determine how much power could
9 be imported over the transmission lines.

10 I think you've seen this map before, the
11 out-of-state resource groups, where there's about
12 5,000 megawatts of wind that are being proposed
13 for Oregon and Washington, 1,000 megawatts over in
14 the Nevada-Idaho area, and then there's this
15 combination of wind and geothermal proposed
16 development that Vulcan talked about earlier, over
17 in the north Reno and south Reno area.

18 And then there are about 1,000 megawatts
19 that are proposed down in southern Arizona. So we
20 took this map and we broke it up into three
21 regional groups. We have the northwest, the Reno
22 area and the southern.

23 Proposed transmission upgrades we looked
24 at was the COI, a trans-Sierra line through
25 Susanville, or around that area somewhere. A

1 trans-Sierra line over through Truckee.

2 What to do with the DC Intertie tap, as
3 far as what value it's getting on the DC and
4 looking at Palo Verde two. If that was the
5 reconstructing in mind how much would we do.

6 It's interesting, in our preliminary
7 analysis to date that the COI line shows up as
8 being our limiting factor. Even with building
9 Palo Verde-Devers 2 and then looking at transfer
10 capability, the COI, in our initial analysis is
11 becoming to show up as the limiting element to
12 imports.

13 Contingency analysis of the California
14 system shows that we would have some
15 infrastructure problems on the 230. For example,
16 if we were to build a fourth COI line and bring it
17 down to Tracy or to Tesla we'd begin to overload
18 some of the 230 lines, because we're trying to
19 push a lot of power out to load center.

20 And upgrading the 500 system would have
21 limited benefit without upgrading the
22 infrastructure to get it from the connecting
23 points to the load.

24 The conclusions are that the COI is
25 vulnerable for outages and limits the import

1 capability. And as I said, we're just now getting
2 into doing this, and the workshop where we'll be
3 going into a lot of detail will be May 9th, where
4 we'll get into a lot of detail on its impacts.

5 I just wanted to give you an idea of
6 some of the things we were looking at and studying
7 during this time period. And looking at how much
8 we can bring in from out-of-state without going to
9 major upgrades to the system.

10 And that's really all i have until we do
11 the May 9th workshop.

12 COMMISSIONER GEESMAN: Steve?

13 MR. MUNSON: The study starts in 2010?

14 MR. DAVIS: Yes.

15 MR. MUNSON: You know, I would strongly
16 suggest if possible that you start looking at the
17 situation in 2007. You end up with this problem
18 saying that the COI is at 95 percent and PGCi is
19 at 85 percent in 2010. However, in the current
20 time frame PGCi is thought to have some expansion
21 left and indeed Sempra's trying to build a 1,400
22 megawatt coal plant on PGCi.

23 So I would be really interested, and I
24 know other developers would, in seeing what these
25 systems look like in '06, '07, '08 and '09. And

1 further, need to point out, of course, that in
2 2010 the accelerated RPS is over, the ballgame's
3 over. We've already missed the barn.

4 MR. DAVIS: Well, the idea of studying
5 2010 was to say what problems are reoccurring and
6 what do we got to do now to get ready to bring in
7 renewable energy resources. If you remember, the
8 other comment I had is we're looking at power
9 flows that the utilities are projecting to use.

10 So in 2010 we're actually using the
11 forecast of when the utilities are moving on the
12 line. Also remember I made the comment there's a
13 difference between what's being shown on the
14 transmission lines that come in and what's been
15 based on historical.

16 Because one of the things we don't know
17 is how much of the additional transmission is
18 being used to bring home spot markets prices and
19 everything to keep the utilities' costs under
20 control. But there is that little bit of
21 discrepancy that I talked about, that the loading
22 is an issue of really how much is coming in on the
23 line.

24 I've heard talks, and then seen things
25 where people were talking about 2,700 megawatts is

1 all that is being utilized, or maybe even a lower
2 number, on the DC line. But with the losses, and
3 even if you fully load at 3,300 your losses are
4 going to bring it down to about 2,700 or therefore
5 I think at Sylmar.

6 So you lose a lot in the losses on the
7 line coming down. So I'm not sure, if we go back,
8 and one of the things we have to be careful of is
9 if we go back and we start reducing the DC line
10 then we're going to have to make some assumptions
11 on starting up other generation within the area or
12 doing something else.

13 And I'm not sure if want to get in to
14 that type of analysis right now. We're using the
15 best guess by the utilities on the loading of the
16 lines for 2010 and 2017.

17 MR. MUNSON: If I could, just to finish
18 that, though. You know, from a policy standpoint
19 you don't want to look at what the utilities or
20 anybody else does, what they think is going to
21 come on in 2010, and accept that as the way it's
22 going to be.

23 I believe you need to look at how the
24 system is today and then put renewables on at
25 least equal footing to compete for what we think

1 is a lot of available capacity now. And so, if we
2 know what the numbers are today then the policy
3 decisions could be made for allowing renewables to
4 be the ones that build the system up.

5 I would ask for that level of evaluation
6 if you can do it.

7 MR. DAVIS: We'll look into it. I know
8 what you're saying, and that was one of the issues
9 that I brought up here when I said there's a
10 difference between historical loading and
11 projected loading on the transmission system. And
12 so that's an issue that we need to look at and
13 resolve.

14 That's one of the reasons why I brought
15 that up and showed it on the board, is that we
16 noticed this and we've been looking at it as to
17 why it's like that. And there are things that we
18 can do within our time to be able to look at that.

19 COMMISSIONER GEESMAN: Ron, where do you
20 get your utility assumptions on line loading?

21 MR. DAVIS: We got power flow data sets
22 from each of the major utilities. SCE, San Diego
23 and PG&E have been cooperative in providing us the
24 load flow data. Then we worked with Angela
25 Tangetti in her production costing model, to look

1 at what she models as flows coming in from the
2 line.

3 And we compared that with our low gross
4 so we are consistent between the electricity
5 office and what the utilities are showing, and
6 what our power flows are showing.

7 COMMISSIONER GEESMAN: Thank you.

8 MR. DAVIS: And as I said, that workshop
9 is May 9th. We haven't completed our analysis, I
10 just wanted to give you a first cut overview of
11 the things we were seeing.

12 AUDIENCE: In the production cost
13 simulated modeling, how are you modeling the
14 renewables, and how are you putting it under, just
15 to go back to the gentleman's question as to
16 thermal, because under certain circumstances the
17 renewables are maybe available, and disadvantaged
18 because of the cost or partial operation or even
19 some of the transmission upgrades are computer
20 based. So how are you guarding for that fact?

21 MR. DAVIS: As I said before, we're not
22 running production costing right now, we're
23 looking at transmission load flows. I was just
24 comparing and making a comment that we compared to
25 the power simulation studies so that we could get

1 the power flows across the interties correct, and
2 look for a consistency there.

3 Right now, since we're looking at ATC,
4 the transport capability, we're looking at only
5 the current loading on the line and how much work
6 can be brought in on the system. And in this
7 phase of the work, when you're looking at what's
8 currently being scheduled on to the line for the
9 summer peak, and then how much additional transfer
10 capability there would be.

11 I said before that you need to go beyond
12 that a little bit more and look at power
13 simulations to look at more hours or more effects
14 on the system, but that has not been done yet.
15 Yes?

16 AUDIENCE: Just a comment. Just because
17 it's currently being done doesn't mean it's
18 optimum or desirable.

19 MR. DAVIS: And as you remember, one of
20 the asides I said when I was comparing historical
21 to projected, there is a difference. And I
22 brought that up right at the beginning as
23 something that needs to be looked at and
24 considered as you're doing transfer capability.
25 So we recognized that right from the beginning.

1 That was the purpose of showing this in
2 advance, was just to give you an idea of some of
3 the issues and some of the things we're trying to
4 look at as transfer capability.

5 COMMISSIONER GEESMAN: I think you were
6 also trying to sell tickets for the May 9th
7 workshop.

8 MR. DAVIS: Elaine told me to do that.

9 COMMISSIONER GEESMAN: Thanks, Ron. And
10 we do look forward to the May 9th presentation.
11 Any questions, comments, observations?

12 Don, are we done?

13 MR. KONDOLEON: We actually were going
14 to have a brief panel discussion that Elaine was
15 going to facilitate, and the goal of the panel
16 discussion was really to talk about state actions.
17 What sort of actions the state could move forward
18 with on both the production side and with regard
19 to resolving some of these constraints.

20 I know the goal is to try to get out of
21 here certainly before 1:00. So if we could have
22 Elaine facilitate that discussion we'll go ahead
23 and begin.

24 MS. SISON-LEBRILLA: Okay, while I'm
25 trying to get this presentation off the screen,

1 can I have Mr. Frank Barbera from IID, Assistant
2 Manager, please come and sit in these L-shaped
3 tables.

4 And Jonathan Weisgall, VP, MidAmerican
5 Energy Holding Company, please come forward to the
6 L-shaped table. Ellen Allman, Business Manager,
7 CAITHNESS Operating Company; Tom O'Connor
8 representing Ormat; Dave Geier, SDG&E, and Jim
9 Filippi from PG&E.

10 Thank you all for agreeing to
11 participate. This is going to be a really
12 informal panel session, and essentially what I had
13 envisioned was asking you all to essentially
14 consider what we had presented to us this morning,
15 and also to talk about and try to answer and
16 respond to these panel discussion questions that
17 is on the bottom of your agenda.

18 What can and should the state be doing
19 to promote the development of geothermal resources
20 within California, and what obstacles exist?

21 How can and should the state improve
22 access to the electricity grid by new geothermal
23 resources, both short-term and long-term?

24 And what we'll do is we'll ask each of
25 you to comment on that, and please try to be

1 brief. We'll have questions from the
2 Commissioners, and also questions from the
3 audience and participants if they wish. And also
4 any comments that other folks would like to make
5 with respect to these questions.

6 Okay, shall we begin. Let's start with
7 IID?

8 MR. BARBERA: Sure. What IID sees is
9 that there's a lot of good renewable resources out
10 there. There's a lot of good transmission plans
11 that are out there.

12 But they all need to be implemented and
13 implemented together. And the work needs to work
14 across the Western Interconnect. So we need to be
15 able to build joint transmission projects, we need
16 to have that be timely implemented with energy
17 contracts between load serving entities and the
18 renewable producers.

19 We need to bring them and the barriers
20 might exist, particularly between the financial
21 models and the physical models that exist between
22 the various agencies within the Western
23 Interconnect.

24 And we believe that that can be done,
25 that we can marry those those worlds, through

1 perhaps a contract means or an agreement to be put
2 in place as such. And in that way we can actually
3 get those transmission plans built, give access to
4 those energy suppliers, so that the renewables can
5 be brought online, and all the initiatives met.

6 COMMISSIONER GEESMAN: What's the
7 evidence that there is the potential for a
8 compatible arrangement between the financial model
9 grid operators and the physical operators?

10 MR. BARBERA: The way I view it that
11 perhaps transmission ownership rights would
12 prevail, such that in some of the transmission
13 companies, they can exist with their own tariffs
14 and their own control, that portion of the line.

15 Others that would have ownership would
16 certainly have their price guarantees and
17 operational guarantees. If it pulls within the
18 WECC control area, where the transmission system
19 lies would be within the control of the agencies
20 that are within that area.

21 Or perhaps it could be under the control
22 of those that come together to be participants in
23 the transmission lines per se.

24 COMMISSIONER GEESMAN: Thank you.

25 MS. SISON-LEBRILLA: Other questions?

1 Okay, Jonathan Weisgall, MidAmerican Holding?

2 MR. WEISGALL: Good afternoon,
3 Commissioners. I guess trying to limit the
4 questions just to the transmission issues, I guess
5 as a developer there are two things we look for.

6 One is that great oxymoron in the sky,
7 regulatory certainty. Kind of like army
8 intelligence. But you want to know where the
9 state is going, you also want to know where the
10 feds are going. That's one component.

11 The other component is the right market
12 signals. I think with the Imperial Valley Study
13 Group, I think the state is doing the right thing.
14 I emerged from these presentations this morning
15 confident that the work is being done, the
16 timetable looks pretty good.

17 I have questions more or less outside
18 this workshop. For example, I see the
19 announcement of the new frontier line as another
20 transmission line development. I wonder where
21 that fits in to the game plan of promoting
22 renewables in the state.

23 That doesn't necessarily -- in fact a
24 company like mine could build a line like that --
25 so it's not a question of the need for that it's

1 really more where is the state in terms of lining
2 up renewables.

3 I've heard you, Commissioner Geesman,
4 say repeatedly that the assumption for new
5 generation has got to be renewables, given the
6 need to meet this mandate. It's going to be the
7 going-in assumption.

8 That's useful. As a developer we need
9 to continue to see the market signals. Bottom
10 line, in terms of the impediments, they're costs.
11 And a lot are outside the scope of this workshop.

12 The single most important incentive that
13 a geothermal developer needs today is a federal
14 production tax credit. That's something being
15 worked on back in Washington, and it is part and
16 parcel to the need to recognize the fact that
17 geothermal is different from wind in many ways.

18 One of the most important is the
19 timeline for construction. We have before the
20 Commission, well we have a revised plan actually,
21 for our new Salton Sea plant, but even with a
22 permit to build, with a customer, with a power
23 purchase agreement, with construction contracts,
24 ready to go, with financing ready to go, we could
25 put the shovel in the ground tomorrow, you're

1 talking 27 months construction time.

2 There's a need to work some tax
3 incentives that way. But I think, the one comment
4 I have is really praise for the way the Commission
5 has attacked this problem. I think your Tehachapi
6 group has done the same with wind, and I think the
7 Imperial Valley Study Group is off to the same
8 footing.

9 And one thing you can do here that you
10 can't do in other organizations in the state is
11 you can get all the stakeholders to come together.
12 You can get your munis, you can get your IOUs, and
13 I think that's the best way to do the planning.

14 COMMISSIONER GEESMAN: Are you familiar
15 with the Southern California Edison renewable
16 trunkline proposal that they've filed with FERC?

17 MR. WEISGALL: Yes.

18 COMMISSIONER GEESMAN: Do you think
19 that's a model that's likely to prove useful in
20 the geothermal area as well?

21 MR. WEISGALL: It's certainly something
22 worth taking a very hard look at. We want to be
23 supportive to Edison in its efforts at FERC to,
24 because, I mean, one of the big issues here is if
25 the policy goal of the state is to promote

1 renewables, what about socializing the cost of the
2 transmission line to do that. It's part and
3 parcel.

4 COMMISSIONER GEESMAN: It strikes me
5 that we're going to need to pre-build a fair
6 amount of transmission to develop all of these
7 resources. And that will require that we change
8 the way we have traditionally looked at
9 transmission development, and as you say,
10 socialize that risk.

11 I think that's unavoidable in this area,
12 and the consequences of not being willing to come
13 to grips with that I think is to continue to
14 expose our system and its customers to an
15 unbelievable level of vulnerability to fuel cost
16 volatility and recently fuel cost escalation.

17 The answer to doing nothing I think ends
18 up to being a continued exposure to pretty
19 volatile fuel costs and lodged against that I
20 think this Commission, the Public Utilities
21 Commission, and the FERC need to evaluate whether
22 it is worthwhile to build transmission lines in
23 advance of, in our situation, winning RPS bids.

24 MR. WEISGALL: Well, two quick comments
25 on that. One, I made a note on my pad, when David

1 was talking from San Diego Gas and Electric, it
2 was a very telling point. You said we are going
3 to file before we have every single T crossed and
4 I dotted. You can't, I mean, the conditions are
5 different.

6 My second comment is that also may
7 require the FERC to take a look at return on
8 equity, because there is more risk here ,there's
9 no question about it. And again, that's outside
10 your framework, but you work cooperatively with
11 these other agencies and I think that's something.

12 FERC is holding a workshop, I think it's
13 April the 22nd, it's a Friday, and the topic of
14 the workshop is why isn't there more transmission
15 infrastructure investment taking place?

16 Well, I work for a very large company,
17 we allocate capital, we're looking to allocate
18 capital all the time, and you want to allocate the
19 capital where you can get a good return and it may
20 be that transmission, that the FERC needs to take
21 a look at that issue.

22 COMMISSIONER GEESMAN: Well, one thing
23 that's not outside our purview is the focus on the
24 fact that transmission represents a relatively
25 minuscule portion of every customers bill. In

1 California it's in the four to five to six percent
2 range, across the state.

3 And as a consequence, particularly given
4 the impact on the other 95 percent of the bill, I
5 think this is an area where the state should be
6 willing to incur some risk.

7 MR. WEISGALL: Couldn't agree more,
8 couldn't agree more.

9 COMMISSIONER GEESMAN: Thanks, John.

10 MS. SISON-LEBRILLA: Okay, Tom O'Connor,
11 representing Ormat.

12 MR. O'CONNOR: On behalf of Ormat we
13 appreciate the opportunity to participate in these
14 proceedings. I'm in a position just to talk about
15 a few issues, given the time we have before us
16 this afternoon.

17 You've heard Ron Davis talk about line
18 losses. I think it's important maybe to drill
19 down a little bit and take a look at what are the
20 causes of those line losses. Are they just policy
21 or are they technical?

22 And without getting into apportioning a
23 percentage of those components at fault, I think
24 it may be an opportunity for another workshop or
25 have staff take a look at the causes of the line

1 losses.

2 One potential cause would be the ability
3 of the ISO to curtail imported power. And from
4 what I understand, they're able to curtail six to
5 15 percent of imported power. And that should be
6 a factor as you take a look at importing
7 geothermal coming in from Nevada.

8 Another potential cause for line loss
9 could be on the technical side. Just in the
10 components that make up the line, and I'm not an
11 engineer so I shouldn't get into components, but I
12 do realize there are opportunities to look at
13 programs that could be collaborative with the DOE
14 and the PIER program to use superconducting
15 materials to minimize line losses. So I encourage
16 the Commission staff to take a look at those
17 causes.

18 There's a second issue that maybe needs
19 a little more collaborative attention, is the
20 ability to work with the BLM. And look at their
21 ability to make more leases available and see what
22 kind of amount of geothermal or steam is available
23 in California and also in Nevada.

24 And related to that issue is the ability
25 of the Commission staff to work with BLM and EPA

1 and others to streamline the permitting process.
2 It'd be nice to have EPA and BLM at the table to
3 put their processes on the record.

4 A final question, in terms of
5 collaboration, is to seek more active
6 participation with the municipal utilities for the
7 Northern California Public Power Authority and the
8 Southern California Public Power Authority.

9 From a company perspective, Mammoth has
10 three sites, two in Imperial Valley and one to
11 Mammoth. We've heard today the issues about
12 putting additional transmission in the Imperial
13 Valley. We welcome a collaborative process going
14 on in the Imperial Valley and participation in
15 that.

16 There is a cone up the side of Mammoth,
17 and they are located very close to the SEC
18 substation there, but there also needs to be taken
19 a look at maybe socializing the cost of maybe
20 adding a transmission line so you can enhance the
21 flow of geothermal to the municipal utilities in
22 southern California so they can more easily
23 participate in meeting the RPS goals for 2010 and
24 2017.

25 And those are the extent of our oral

1 comments.

2 COMMISSIONER GEESMAN: Is Bill Gould on
3 the Ormat board?

4 MR. O'CONNOR: No, he is not.

5 COMMISSIONER GEESMAN: He was one of the
6 Ormat founders. Was he involved --?

7 MR. O'CONNOR: Before my time, but I can
8 get that to you.

9 COMMISSIONER GEESMAN: Yeah, I'd be
10 curious.

11 MS. SISON-LEBRILLA: Okay, Ellen Allman,
12 Caithness Operating Company.

13 MS. ALLMAN: Hi, good morning. I don't
14 really have too much to add to what's been said by
15 my colleagues to my left. I just want say, to use
16 an old adage, if you build it we will come. I am
17 responsible for doing economic analysis on what to
18 pay prices on projects.

19 And when you throw the transmission
20 component in there, trying to compete makes it
21 very difficult. But for the transmission
22 component there'd be probably more RPS, rates that
23 would be accepted as the low cost, for at least
24 the short list.

25 So, I think the Imperial Valley is a

1 great model. I'd like to see that they would be
2 making more of those study groups being done in
3 other areas outside of the Imperial Valley.

4 We are mostly out-of-state, and we have
5 mostly out-of-state potential in the Nevada
6 corridor. The one thing that I know is going to
7 be an issue I think in 2007 is when they go to, I
8 believe it's called LMP, the line nodal pricing,
9 getting away from the GMM's using this congestion
10 pricing losses that there is going to be a
11 significant impact on any renewable outside the
12 state.

13 That could take upwards of ten percent
14 off the price, and that could, again, price us out
15 of the market there. So, I know there are some
16 issues about the delay in the implementation of
17 the compensation for the overcharging of that.

18 I know that's outside of this workshop,
19 but that is an issue for us coming up in the
20 future as well.

21 COMMISSIONER GEESMAN: Where else
22 besides the Imperial Valley would you direct our
23 transmission attention?

24 MS. ALLMAN: Well, selfishly, we have an
25 issue in control. It's not a hot spot,

1 unfortunately. ?That would be nice if there was
2 some focus being put on the fact that south and to
3 Bishop is, it's pretty much at its max right now.
4 And I know folks at Mammoth as well.

5 And unfortunately I know that there's a
6 significant price tag probably to increase the FCE
7 capability, but there may be a solution as to
8 going across the LAWPD territory. I don't know
9 how well they're working together on that.

10 Because we have both the coastal plant
11 which is in controls as well. So there is a
12 significant bottleneck of geothermal in that spot
13 right there.

14 COMMISSIONER GEESMAN: Do you have
15 projects in Nevada that would be interested in a
16 tap into the DC line?

17 MS. ALLMAN: We do, although we can as
18 easily come down our own Dixie Valley line, so
19 we'd have less of an interest in that. We'd
20 probably be better off coming into the control
21 area.

22 COMMISSIONER GEESMAN: Okay. Thank you.

23 MS. ALLMAN: Thank you.

24 MS. SISON-LEBRILLA: Jim Filippi, PG&E?

25 MR. FILIPPI: Yes, good afternoon. I

1 guess I would like to concentrate on development
2 of transmission, my remarks to development of
3 transmission. And I think one of the things the
4 Energy Commission can provide, as far as guidance
5 to the utilities on this area, is an integrated
6 energy policy.

7 We've seen some great presentations here
8 today on development of geothermal. Sounds good,
9 but we're seeing a lot of presentations for other
10 types of resources, even conventional resources,
11 like we've heard for the Frontier line.

12 So, and developing transmission somewhat
13 in advance of procurement process that's fine too,
14 as long as we're sure that we're doing the right
15 transmission lines. And to do that we really need
16 to, as Ron Davis mentioned, consider the whole mix
17 of resources that we're going to need for the
18 state.

19 Our charge has been to get the mix of
20 resources that's least cost best fit, and that
21 includes transmission. So that's really what
22 we're looking for in terms of guidance, and
23 anything the Energy Commission could do to help us
24 sort that out would be greatly appreciated.

25 Another thing I would like to mention

1 is, we've heard some talk today about it would be
2 good to have some other study groups. I'd like to
3 point out that there are other study groups that
4 are working right now in some of these areas of
5 interest.

6 In the northwest, including northern
7 California, there's a group called Northwest
8 Transmission Assessment Committee, or NTAC, that
9 is working on issues similar to what the group in
10 southern California, STEP, has done.

11 And these groups do strategic studies,
12 including production simulations, that consider
13 resource proposals and how transmission could be
14 developed to access those resource proposals.

15 And so I would encourage resource
16 developers to get involved in those studies, and
17 state agencies as well, some of the already are,
18 to provide more information farther in advance of
19 what potential promising resources may do.

20 The further in advance we can get a look
21 at these proposals and see what's shaking out to
22 be competitive the better transmission information
23 we can develop before we get into procurement.

24 Another group is the RMATS group in the
25 Rocky Mountain area. They're the ones who did the

1 initial work on the Frontier line.

2 So, again, these groups are out there, and I
3 would encourage developers to work with those
4 groups, identify their potential resource
5 alternatives, and let those groups start working
6 on conceptual plans for their resources. Thank
7 you.

8 COMMISSIONER GEESMAN: Were you in the
9 room when, I think it was Ron Davis that put up
10 the numbers for the Sonoma-Lake County geothermal
11 resource areas? And made his comments about
12 transmission needs, to further develop what I
13 think was 250, 300 megawatts of incremental
14 capacity there?

15 MR. FILIPPI: Yes, I was here.

16 COMMISSIONER GEESMAN: I had not heard
17 numbers that large before. Is that an area that
18 you envision needing additional transmission
19 investment in the future?

20 MR. FILIPPI: I am not really familiar
21 with the numbers on development for transmission
22 from the geysers. I expect that Ron probably took
23 those numbers from documents that were presented
24 by PG&E, such as in the annual transmission
25 expansion plan.

1 So I am aware that, generally speaking,
2 larger increments, to access larger increments of
3 renewable resources on an accelerated schedule
4 will take significant transmission investment. If
5 it was phased out through a longer time, such that
6 low growth could come on and absorb some of that
7 locally it would help.

8 So I am, I guess, off the top of my head
9 I have no reason to doubt Ron's numbers.

10 COMMISSIONER GEESMAN: As it relates to
11 your comments about an integrated energy resource
12 policy, I certainly agree with you.

13 I will say, one of the thing that is
14 particularly frustrating in that regard -- because
15 I think the state has attempted to articulate a
16 pretty clear and, for the last couple of years a
17 pretty consistent set of policy priorities -- when
18 I reflect back on our 2003 IEPR cycle, and the gas
19 price forecast that underlay all of it.

20 And as I think most of the people in the
21 room know, that gas price projection drives an
22 awful lot of the results in any of these models.
23 We had what, at the time, was regarded as a
24 consensus forecast. There weren't really any
25 serious dissenters on it.

1 And we missed the price of gas by more
2 than 100 percent over the past two years. I
3 certainly don't know where gas prices are going to
4 be seven or eight or ten years out, but I note
5 that you can't get a firm bid more than about six
6 months out.

7 So, these are moving targets, and I
8 think to the extent that the state is able to
9 articulate a clear set of policies, and there's a
10 belief across the group of stakeholders that the
11 state is likely to stick to that clear set of
12 policies, requires a certain level of, I guess
13 I'd call it willing suspension of disbelief,
14 because there are an awful lot of imbedded
15 assumptions that are quite likely to be wrong, and
16 which forces us into a question of what would be
17 the most prudent policy.

18 And I suspect it will involve your
19 company and the other utilities engaging in a lot
20 more transmission investment than you would have
21 perhaps ten years ago. And hopefully the state
22 will be there as a partner, providing the
23 necessary assurances of cost recoveries and timely
24 licenses and everything else that goes along with
25 a policy that wants to promote both renewables and

1 a rational transmission buildout. But I think
2 both are required.

3 MR. FILIPPI: I agree.

4 MS. SISON-LEBRILLA: Okay, David Geier,
5 SDG&E.

6 MR. GEIER: Well, I think I'll start
7 with sort of the quick answer. I mean, the first
8 question asked how do we promote the development
9 of geothermal resources. And I think the simple
10 answer is build transmission.

11 I think we've heard today that
12 geothermal -- and if you look at renewables in
13 general, they typically are away from the load
14 centers. And to get to the numbers that we're
15 talking about, the 20 percent, you're going to
16 need transmission to do that.

17 So, I think build transmission, and sort
18 of everything that goes along with that, are my
19 supporting comments here. Because we have to get
20 that right.

21 There's just a couple of things. I did
22 talk about maybe filing before we have every T
23 crossed and I dotted. And quite honestly that
24 scares me. Been there before, and the typical
25 response is, you know, you put together an

1 incomplete procedure, you should have thought of
2 this, this changed.

3 We've been through that battle. That
4 battle can be very expensive, it can be very
5 draining. And we do need support that, you know,
6 we're going to do the best we can. We have a
7 commitment, speaking for SDG&E but I'm sure for
8 the other utilities also, to the environment, to
9 doing things right.

10 But quite honestly I don't think we can
11 wait until we have every detail lined out, because
12 quite honestly it will change by the time we get
13 there.

14 And we do need to look at streamlining
15 the process. I know we've talked about this at
16 previous workshops, but we need to have a clear
17 agency responsible for need, a clear agency
18 responsible for moving forward with the other
19 parts of the licensing. The current model just
20 has too much duplication and too much second
21 guessing of that process.

22 And as I mentioned in my previous
23 statement, historically the need has been based on
24 reliability. Things will change there also. We
25 really think this three-pronged approach of

1 reliability, economics and connection to
2 renewables is the way to really prove the need for
3 a new transmission line.

4 Not just the one in San Diego, and I
5 call it southern California, because if you look
6 at IID's investment, Edison's investment, and our
7 own, it truly is a regional concept that we're
8 looking at, and CFE is always at the table also at
9 all of our meetings. So I think you can really
10 look at southern California/northern Baja together
11 there.

12 And, Commissioner Geesman, your comment
13 on the bill, that's exactly what we're looking at.
14 We think that, if we can build this transmission,
15 with the benefits that we receive from reducing
16 congestion, hopefully we can make these capital
17 investments and not have an upward impact on
18 the bills.

19 And our thought is, if you look where
20 congestion is today, that you could actually
21 reduce the overall bill by having the right
22 resource mix on the commodities side as DWR
23 contracts go away, and reducing the congestion,
24 which quite honestly is just a waste of
25 everybody's dollars at this point.

1 The last comment, I'm not sure just how
2 specific I can be, but just sort of this whole
3 concept of reducing a risk for the utilities to
4 build the transmission.

5 If we truly believe that we can build
6 transmission in advance, before we know exactly
7 where the resources are, hopefully we can do that
8 in a prudent way, but there is risk associated
9 with that, and somehow we have to get the risks
10 and sort of the benefits lined out so that we can
11 get a plan that moves things forward. Thank you.

12 COMMISSIONER GEESMAN: Thanks, Dave.
13 Steve Munson.

14 MR. MUNSON: Ellen from Caithness had
15 been asked if Dixie Valley project, which is a big
16 basin out there that's producing 55 megawatts I
17 think now, would be interested in coming on the
18 PGCI. And she said it would probably be even more
19 cost-effective coming down the Dixie Valley line.

20 That might be true, but one question
21 would be, if the Dixie Valley line can be routed
22 into the green tap on the PDCI at no additional
23 cost, or very little additional cost to you, and
24 then that reduces congestion on the Lugo to
25 control line, that would work for you, wouldn't

1 it? Conceptually?

2 MS. ALLMAN: Uh, conceptually, but, you
3 know, there would be issues as to what that would
4 do to our standing as a QF, but if you make me
5 indifferent to it I don't see why one would be
6 better over the other.

7 COMMISSIONER GEESMAN: What's the QF
8 issue?

9 MS. ALLMAN: Right now, because the line
10 is 100 percent owned by us and it goes directly
11 one way to an open connect, it's technically part
12 of a QF, and it keeps us out of being regulated.

13 COMMISSIONER GEESMAN: Yeah, okay, I
14 follow.

15 MR. MUNSON: And I would like to point
16 out that 27 months to get a plant built is not the
17 short-term solution.

18 And I guess other people in the industry
19 would agree that there will be projects that can
20 get done in 18 months and projects that can get
21 done at 27 months, and shouldn't put that 27 month
22 in front of our brain, I would ask.

23 COMMISSIONER GEESMAN: What do you
24 envision for the contract you just signed with
25 Edison?

1 MR. MUNSON: Those are 18 to 24 month
2 projects, relatively fast track. Because of the
3 status of ten IS and some other things. And it
4 could be 30, but that's outside, depending on
5 agency.

6 And a final thing. I would like you, if
7 you would, as Commissioners, to please consider
8 that our focus has been on projects that need to
9 get up and running in the '07, '08 time frame, and
10 other people have very important larger scale
11 projects that are going to take more time, but we
12 sure hope we don't lose the window of opportunity
13 right now because it's getting tight. I thank you
14 so much.

15 COMMISSIONER GEESMAN: Thank you, Steve.
16 Steven Keller.

17 MR. KELLER: Thank you, Commissioner.
18 Steven Keller with Independent Energy Producers.
19 I just wanted to comment on the conceptual
20 proposal of the trunkline that's been filed at
21 FERC by Edison, which in general I tend to
22 support.

23 And it's great that California is
24 interested in that. I have some concerns about
25 whether FERC will be able to move on that very

1 quickly. It's not clear to me that the other 49
2 states in the nation would be as interested as
3 California is in maybe dealing with that, and
4 there's also going to be a change of the Chairman
5 very shortly who seems to be a supporter of that.

6 I say that raising one observation, that
7 there's a difference between cost recovery and
8 cost allocation. And the trunkline proposal at
9 FERC, in my mind, really focuses importantly on
10 the policy of cost allocation.

11 And I would like to see the state here
12 try to identify a means to provide more assurance
13 to the utilities on the cost recovery, through the
14 PUC or some mechanism here, so that they can start
15 the projects and move forward while they work on
16 cost allocation issues at FERC or wherever it
17 needs to be handled.

18 And if we could figure out how to crack
19 that nut, it would give the utilities the
20 assurance to start the projects now, rather than
21 wait until they've got the cost allocation issues
22 resolved, I think that would get us way past the
23 starting gate and be very helpful.

24 I don't have a resolution to that right
25 now, but I'd like people to start thinking about

1 how to do that. I believe the PUC has, in the
2 past, said that they would provide cost recovery,
3 but it apparently was not provided in a way that
4 gave satisfaction to the utilities and it had to
5 go to FERC.

6 So maybe we could figure out a way to
7 give that assurance, so that we could actually get
8 these projects moving in a more timely fashion.
9 That's my observation.

10 COMMISSIONER GEESMAN: I can't speak for
11 the other Commission, but I do know that they
12 thought they were doing that when they directed
13 Edison to build a line in Tehachapi, and Edison I
14 guess not only didn't feel that it worked for them
15 but sued the PUC successfully.

16 MR. KELLER: Right.

17 COMMISSIONER GEESMAN: So if there is a
18 clear way in which to provide that assurance, I'm
19 sure the CPUC would like to know about it.

20 But my impression right now is that
21 Edison considers it a question of FERC regulation,
22 and does in fact require that the clarification
23 from FERC before it feels comfortable going
24 forward.

25 And certainly, given the comments that

1 Chairman Wood has made, well, I guess it was in
2 December at the FERC technical conference, I would
3 expect that he and his colleagues would be
4 supportive.

5 MR. KELLER: Well, I was at that meeting
6 and I heard his comments. And I took away from
7 that that he was inclined to move forward. As I
8 indicated, he's not going to be the Chairman
9 before this issue is resolved, I don't think, and
10 this is a huge policy issue for the nation as a
11 whole.

12 And while California is very supportive,
13 I think, of this kind of cost allocation issue and
14 socialization of these costs, for a lot of reasons
15 that may not be the policy that could be adopted
16 at a national level.

17 And I'm not convinced that FERC is going
18 to carve out something. So if there's state law
19 that needs to be amended, for example, to provide
20 greater assurance, maybe that's something we can
21 do. It's a new legislative cycle.

22 If there's new language that the PUC
23 could use that might be helpful. I certainly
24 don't want to go through litigation on this again
25 or watch it happen, but maybe there are some

1 solutions that we can give that provide the
2 utilities greater assurance on cost recovery.

3 COMMISSIONER GEESMAN: So are you
4 volunteering to create the Keller working group?

5 MR. KELLER: Well, for this one I would,
6 it would be very interesting to, at least, you
7 know -- I can lead or participate in. Because I
8 think it's an important issue, and it's one that
9 California is way ahead of the other states in
10 thinking about.

11 And we're moving so much more
12 aggressively than the other states on the RPS, but
13 we're getting hung up on this transmission
14 problem. And I don't, we've got to go to the next
15 step.

16 COMMISSIONER GEESMAN: Well, I certainly
17 hope that you're wrong, that it won't be resolved
18 before Commissioner Wood leaves the FERC. I would
19 like to think of this as perhaps his proudest
20 legacy. Or at least the most popular one in
21 California.

22 MR. KELLER: I hope he can get it
23 through. We'll see. Thank you.

24 COMMISSIONER GEESMAN: Thanks, Steve.
25 Other comments or questions?

1 Great. I want to thank all of you for
2 participating today. It's been a very helpful
3 workshop, and we look forward to seeing you again
4 in the near future.

5 (Thereupon, the workshop ended at 12:55 p.m.)

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CERTIFICATE OF REPORTER

I, CHRISTOPHER LOVERRO, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Meeting; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said meeting, nor in any way interested in outcome of said meeting.

IN WITNESS WHEREOF, I have hereunto set my hand this 25th day of April, 2005.

CHRISTOPHER LOVERRO

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